VIRGINIA ELECTRIC AND POWER COMPANY
RICHMOND, VIRGINIA 23261

December 17, 2009

U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, DC 20555

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Docket Nos.	50-280
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VIRGINIA ELECTRIC AND POWER COMPANY
SURRY POWER STATION UNITS 1 AND 2
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION
NRC GENERIC LETTER 2004-02
POTENTIAL IMPACT OF DEBRIS BLOCKAGE ON EMERGENCY RECIRCULATION DURING DESIGN BASIS ACCIDENTS AT PRESSURIZED-WATER REACTORS

By letters dated March 4 (ADAMS ML050630559) and September 1, 2005 (ADAMS ML052500378), November 15, 2007 (ADAMS ML073190553), February 29, 2008 (ADAMS ML080650562), and February 27, 2009 (ADAMS ML090641018), Virginia Electric and Power Company (Dominion) submitted detailed information in response to NRC Generic Letter (GL) 2004-02 for Surry Power Station (Surry) Units 1 and 2.

In a letter dated June 18, 2009, the Nuclear Regulatory Commission (NRC) transmitted a request for additional information (RAI) regarding Dominion's previous responses to GL 2004-02 for Surry Units 1 and 2. Subsequent conference calls were held between Dominion and the NRC staff to clarify the RAI questions and the information necessary to resolve the open items discussed in the RAI. Dominion's response to the NRC RAI is provided in Attachment 1.

The RAI also requested Dominion to provide a safety case describing how the measures credited in the Surry licensing basis demonstrate overall compliance with the applicable regulations as discussed in GL 2004-02. While we believe the safety case has, to a large extent, been presented in previous correspondence, aggregation of information and integration into a cohesive response has been performed and additional information included where appropriate. The safety case for Surry Units 1 and 2 is provided in Attachment 2. Based on the methodology, modifications, and conservatisms described therein, as well as the detailed information provided in Dominion's previous correspondence listed above, Surry is in compliance with the applicable regulations as discussed in GL 2004-02, and the containment sump issues discussed in GSI-191 and GL 2004-02 have been adequately and thoroughly addressed for Surry Units 1 and 2.

Should you have any questions or require additional information, please contact Mr. Gary D. Miller at (804) 273-2771.

Sincerely,

J. Alan Price
Vice President – Nuclear Engineering

Commitments made in this correspondence:
See Attachment 3 – List of Regulatory Commitments

Attachments:

1. Response to NRC Request for Additional Information, Generic Letter 2004-02
2. Safety Case Demonstrating Overall Compliance with the Applicable Regulations Specified in GL 2004-02
3. List of Regulatory Commitments

COMMONWEALTH OF VIRGINIA)
)
COUNTY OF HENRICO)

The foregoing document was acknowledged before me, in and for the County and Commonwealth aforesaid, today by Mr. J. Alan Price, who is Vice President – Nuclear Engineering, of Virginia Electric and Power Company. He has affirmed before me that he is duly authorized to execute and file the foregoing document in behalf of that company, and that the statements in the document are true to the best of his knowledge and belief.

Acknowledged before me this 17th day of December, 2009.

My Commission Expires: 4/30/13.

GINGER L. ALLIGOOD
Notary Public
Commonwealth of Virginia
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My Commission Expires Apr 30, 2013

Notary Public

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Attachment 1

Response to Request for Additional Information
Generic Letter 2004-02

VIRGINIA ELECTRIC AND POWER COMPANY
(DOMINION)
SURRY POWER STATION UNITS 1 AND 2

Response to Request for Additional Information
Generic Letter 2004-02

Surry Power Station Units 1 and 2

By letters dated March 4, and September 1, 2005, November 15, 2007, February 29, 2008 and February 27, 2009 [Agencywide Documents Access and Management System (ADAMS) Accession Nos. ML050630559, ML052500378, ML073190553, ML080650562 and ML090641018, respectively], Virginia Electric and Power Company (Dominion) submitted responses to Generic Letter (GL) 2004-02, "Potential Impact of Debris Blockage on Emergency Recirculation During Design Basis Accidents at Pressurized Water Reactors," for Surry Power Station Units 1 and 2 (SPS 1 and 2).

In a letter dated June 18, 2009, the Nuclear Regulatory Commission (NRC) transmitted a request for additional information (RAI) regarding Dominion's February 29, 2008 and February 27, 2009 supplemental responses to GL 2004-02 for SPS 1 and 2. The NRC's questions and Dominion's responses are provided below.

NRC Question 1

Please describe how much aluminum surface area (from the reactor vessel insulation) would be exposed for a reactor coolant system (RCS) loop break at a reactor vessel nozzle. Please explain whether your chemical effects evaluation considered exposure of this material and whether a break at this location is potentially limiting with respect to potential for sump strainer clogging.

Dominion Response

As identified in the SPS 1 and 2 Containment Debris Walkdown Packages, the reactor vessel and nozzles are insulated with reflective metal insulation (RMI), i.e., stainless steel. However, Chapter 4 (page 4.2-2) of the Surry Updated Final Safety Analysis Report (UFSAR) states that the RMI includes multilayer aluminum foil as the insulating agent. To resolve this discrepancy, reactor vessel insulation drawings, material lists and specifications were reviewed to definitively determine whether aluminum foil was used in the reactor vessel RMI insulation.

Transco Inc. was the manufacturer who supplied the original RMI insulation installed on the Surry reactor vessels. The reactor vessel insulation design drawings for SPS 1 and 2 state that all of the insulation was fabricated with stainless steel. The reactor vessel insulation is shown on station drawings 11448-5.90-6B, 11448-5.90-12B, and 11448-5.90-7B for Unit 1 and 11448-5.90-1C, 11448-5.90-2B, and 11448-5.90-3B for Unit 2. The drawings were issued in 1970 for Unit 1 and 1972 for Unit 2. Additionally, the insulation material shipping list shown on drawing 11448-5.90-11B does not list any aluminum material, and a note on the Surry material list included on this drawing specifies the use of stainless steel foil. Finally, Surry Specifications NUS-2066 and

NUS-2044, *Metal Reflective Thermal Reactor Vessel Head Insulation,* for SPS 1 and 2, respectively, controlled subsequent changes to the reactor vessel insulation. These specifications require the RMI to be fabricated with stainless steel inner and outer casings and stainless steel foils.

As a result of the above review, it is concluded that the reactor vessel RMI is made of stainless steel and does not use aluminum foil. Therefore, the Surry UFSAR will be revised to remove the statement associated with the aluminum foil.

Based on the above information, it is concluded that the break at the reactor vessel nozzle does not contribute to the aluminum inventory and/or chemical effects evaluation and is not limiting. A break inside the Steam Generator cubicle remains limiting with respect to potential containment sump strainer clogging.

NRC Question 2

Please describe the construction details for the asbestos and asbestos/Cal-Sil insulation at Surry and provide results of evaluation of the similarity of these materials in the plant to the Cal-Sil material whose testing formed the basis for the zone of influence (ZOI) value of 5.45D that is referenced in NEI 04-07 and the corresponding NRC safety evaluation, cited in the February 29, 2008, supplemental response as applicable to the Surry Power Station (SPS) asbestos and asbestos/Cal-Sil. Please also explain how the base material, jacketing, and banding for the material in the plant are similar to the properties of the tested material used to derive a 5.45 ZOI.

Dominion Response

During construction of SPS 1 and 2, asbestos and asbestos/cal-sil insulation was jacketed with a 1925 glass cloth jacketing system manufactured by J.P. Stevens & Co. The jacketing was attached with Benjamin-Foster 30-36 Sealfas adhesive and two coats of epoxy enamel. However, documentation verifying qualification of the jacketing system for a Design Basis Accident (DBA) could not be located. Therefore, asbestos and asbestos / cal-sil insulation located in the containment was re-jacketed using DBA qualified stainless steel jacketing over the original 1925 glass cloth jacketing. The stainless steel jacketing properties and installation configuration are as follows:

- Jacketing material is Type 304 or 316 stainless steel with a thickness of 0.010" or 0.016" (low traffic areas) and 0.020" (high traffic areas).
- Jacketing is applied with horizontal & vertical overlaps in order to shed water.
- Jacketing is attached with stainless steel banding located no greater than 18" on centers secured with mechanical tightening devices with the ends secured with mechanical fasteners that permit a flat joint.

- Stainless steel banding dimensions are 0.5" x 0.02" for piping less than 12" in diameter and 0.75" x 0.02" for piping 12" in diameter and greater.

ZOI Values for Asbestos/Cal-Sil and Asbestos

1. Asbestos/Cal-Sil:

The design calculations utilized the attributes of cal-sil insulation when evaluating the effects of the insulation category asbestos / cal-sil. In accordance with NEI 04-07 and its associated NRC SER, Table 3-2, the ZOI value for cal-sil of 5.45D is utilized for asbestos/cal-sil insulation.

- Jacketing Properties and Configuration

  The industry has performed several tests with cal-sil to establish a ZOI. Industry testing was reviewed and compared based on the similarities in the jacketing materials and configuration to those used on cal-sil insulation at Surry Power Station. This evaluation determined an appropriate ZOI based on the jacketing materials and configuration.

- Air Jet Impact Testing

  The Air Jet Impact Tests (AJITs), CDI Report No. 96-06, tested cal-sil with aluminum jacketing secured with 0.75" stainless steel bands with fold over closures placed approximately 10" apart on centers. The target pipes for the testing were 12" NPS. The banding used in the AJIT is similar to the installation configuration at Surry Power Station with the exception of band spacing (10" vs. 18"). The tests results documented that at a surface pressure of approximately 160 psig, the left banding strap on the jacketing was removed and the jacketing facing the jet nozzle was damaged, but the jacketing remained on the piping. The 160 psig recommended destruction pressure, adjusted for a two-phase PWR jet instead of an air jet (40% reduction per NEI 04-07, NRC SER), results in a ZOI of approximately 2D (NEI 04-07, Table I-3 of Appendix I).

  To disposition the difference in band spacing used at Surry versus the band spacing used in the AJITs, Finite Element Analysis (FEA) modeling will be performed to demonstrate that the stresses induced would be significantly less than the tensile strength of the stainless steel jacketing used at Surry. Specifically, a model will be developed to baseline the test case of the jacketing system with 10" band spacing. A unit force will then be developed to reflect the force imparted on the test jacketing. The unit force developed in the model will then be applied to the Surry jacketing system with 18" band spacing for comparison and to confirm that the as-installed jacketing system will adequately perform its design function.

- Two Phase Jet Testing

  Ontario Power Generation (OPG) Document No. N-REP-34320-10000 performed two phase jet tests on cal-sil insulation with aluminum cladding. The aluminum cladding was 0.016" thick and secured with 0.02" thick stainless steel bands placed 6.5" to 8" apart on centers. The test results demonstrated destruction at a pressure of 24 psig (5.45D ZOI) compared to the AJIT results at 160 psig. The significant difference in destruction pressures was attributed to: 1) a two phase jet vs. an air jet, 2) the seam orientation of the metal jacketing, 3) banding strength and, 4) jacketing thickness. OPG testing determined that the primary failure mode was tearing of the aluminum cladding due to the high stresses induced along the banding interface. The aluminum cladding used was Aluminum Alloy 1100, and has a tensile strength of 13 ksi. The stainless steel jacketing used at Surry (type 304 and 316) has a tensile strength of 85 ksi. Based on a higher tensile strength, a larger destructive pressure would be required to achieve similar results. Therefore, a 5.45D ZOI would be conservative for the destruction of the stainless steel jacketing.

  Initial OPG testing determined that seam orientation of the metal jacketing influenced the destructive pressures. OPG performed additional testing with two layers of jacketing, offsetting the horizontal seam locations. The results of the OPG testing showed a two layer jacketing system with offset seams resulted in a significant decrease in the ZOI radius. Surry has a similar two jacket configuration. The insulation jacketing seams for both systems are not aligned. The outer stainless steel jacketing system has a linear horizontal seam. The 1925 glass cloth jacketing system is wrapped around the piping and does not expose a linear seam to any jet. Therefore, based on the OPG testing, a ZOI less than 5.45D could be justified based on the stainless steel jacketing and crediting a double jacketed system.

<u>Conclusion</u>:

The review and comparison of insulation material and jacketing properties and configuration established a range of ZOIs from 2D to 5.45D. The majority of industry testing supports a ZOI of 5.45D or less. A ZOI of 5.45D was selected for the design of the strainer because this provides a reasonable degree of assurance that the cal-sil insulation and jacketing systems have been categorized properly.

As noted above, FEA modeling will be performed to demonstrate that the band spacing used for the stainless steel jacketing installed at Surry is acceptable. The FEA will be completed by January 31, 2010.

2. Asbestos:

At Surry Power Station, the initial debris generation evaluation utilized 5.45D ZOI for asbestos insulation. This was reported in the February 2008 supplemental response letter. Since then, the debris generation and transport calculations have been revised to increase the ZOI to 7D. The following provides a basis for utilizing a ZOI of 7D for asbestos insulation.

Basis for ZOI Values for Asbestos

The industry has not performed ZOI testing for asbestos insulation. In the absence of testing, NEI 04-07 states that it would be conservative to use the same destruction pressure as low density fiberglass (LDFG). Using the correction factor (40%) for materials characterized with air jet testing identified in Staff Evaluation of §3.4.2.2 of the NRC's SER to NEI 04-07, the destruction pressure of LDFG is 6 psig which results in a ZOI of 17D. A reduced ZOI is justified by evaluating: 1) asbestos material properties and 2) jacketing properties and configuration.

- Material Property Comparison:

  Per NEI 04-07, LDFG has a density of 2.4 lb/ft3 and a ZOI of 17D. High Density Fiber Glass such as TempMat has a density of 11.8 lb/ft3 and a ZOI of 11.7D. Asbestos has a density of 7 to 10 lb/ft3. The comparison of materials based on densities implies that asbestos is a more durable material than LDFG and would tend to have a similar ZOI to HDFG. This is further justified per the comparisons provided below. The original insulation specification for Surry Power Station lists several asbestos types, including Pittsburgh-Corning's Unibestos, for use within containment. Pittsburgh-Corning's Unibestos is used for comparison in this review. Unibestos has the following material properties:

  - Tensile strength of 67 psi
  - Modulus of rupture (force required to break a specimen) ranges from 73.2 – 94.9 psi
  - Compressive strength of 1800 psf (12.5 psi) at 5% deformation

  Depending on the postulated failure mechanism (tensile, compressive, or flexural) the destruction pressure ranges between 12.5 psi to 94.9 psi. Based on this pressure range, a ZOI between approximately 2D and 10D per Table I-3 of Appendix I of the NRC's SER to NEI 04-07 is determined to be appropriate. This confirms that asbestos would tend to have a smaller ZOI compared to LDFG.

- Jacketing Properties and Configuration

  The industry has not performed any testing with asbestos to establish a ZOI for this material. Industry testing was reviewed and compared based on the similarities in the jacketing materials and configuration to those used on asbestos insulation at Surry Power Station. This evaluation determined an appropriate ZOI based on the jacketing materials and configuration.

- Air Jet Impact Testing

The Air Jet Impact Tests (AJITs), CDI Report No. 96-06, tested cal-sil with aluminum jacketing secured with 0.75" stainless steel bands with fold over closures placed approximately 10" apart on centers. The target pipes for the testing were 12" NPS. The banding used in the AJIT is similar to the installation configuration at Surry Power Station with the exception of band spacing (10" vs. 18"). The tests results documented that at a surface pressure of approximately 160 psig, the left banding strap on the jacketing was removed and the jacketing facing the jet nozzle was damaged, but the jacketing remained on the piping. The 160 psig recommended destruction pressure, adjusted for a two-phase PWR jet instead of an air jet (40% reduction per NEI 04-07, NRC SER), results in a ZOI of approximately 2D (NEI 04-07, Table I-3 of Appendix I).

To disposition the difference in band spacing used at Surry versus the band spacing used in the AJITs, FEA modeling will be performed to demonstrate that the stresses induced would be significantly less than the tensile strength of the stainless steel jacketing used at Surry. Specifically, a model will be developed to baseline the test case of the jacketing system with 10" band spacing. A unit force will then be developed to reflect the force imparted on the test jacketing. The unit force developed in the model will then be applied to the Surry jacketing system with 18" band spacing for comparison and to confirm that the as-installed jacketing system will adequately perform its design function.

- Two Phase Jet Testing

Ontario Power Generation (OPG), Document No. N-REP-34320-10000 performed two phase jet tests on cal-sil insulation with aluminum cladding. The aluminum cladding was 0.016" thick and secured with 0.02" thick stainless steel bands placed 6.5" to 8" apart on centers. The test results demonstrated destruction at a pressure of 24 psig (5.45D ZOI) compared to the AJIT results at 160 psig. The significant difference in destruction pressures was attributed to: 1) a two phase jet vs. an air jet, 2) the seam orientation of the metal jacketing, 3) banding strength and, 4) jacketing thickness. OPG testing determined that the primary failure mode was tearing of the aluminum cladding due to the high stresses induced along the banding interface. The aluminum cladding used was Aluminum Alloy 1100, and has a tensile strength of 13 ksi. The stainless steel jacketing used at Surry (type 304 and 316) has a tensile strength of 85 ksi. Based on a higher tensile strength, a larger destructive pressure would be required to achieve similar results. Therefore, a 5.45D ZOI would be conservative for the destruction of the stainless steel jacketing.

Initial OPG testing determined that seam orientation of the metal jacketing influenced the destructive pressures. OPG performed additional testing with two layers of jacketing, offsetting the horizontal seam locations. The results of the OPG testing showed a two layer jacketing system with offset seams resulted in a significant decrease in the ZOI radius. Surry has a similar two jacket configuration.

The insulation jacketing seams for both systems are not aligned. The outer stainless steel jacketing system has a linear horizontal seam. The 1925 glass cloth jacketing system is wrapped around the piping and does not expose a linear seam to any jet. Therefore, based on the OPG testing, a ZOI less than 5.45D could be justified based on the stainless steel jacketing and crediting a double jacketed system.

Conclusion:

The review and comparison of insulation material and jacketing properties and configuration established a range of ZOIs from 2D to 10D. The majority of industry testing supports a ZOI of 5.45D or less. A ZOI of 7D was selected for the design of the strainer because this provides a reasonable degree of assurance that the asbestos insulation and jacketing systems have been categorized properly.

As noted above, FEA modeling will be performed to demonstrate that the band spacing used for the stainless steel jacketing installed at Surry is acceptable. The FEA will be completed by January 31, 2010.

NRC Question 3

Please provide additional information that justifies the temperature/viscosity extrapolation of data from test temperatures to predicted loss-of-coolant accident (LOCA) temperatures. Based on recent review of Rig 33 head loss traces for North Anna during the chemical effects audit of that plant, the staff believes that there may not have been "sudden" decreases in measured head loss, but there were anomalous observations of fairly large and relatively fast head loss decreases for qualification tests and other non-qualification tests for North Anna. Flow sweeps were done for some of the tests that seemed to indicate that boreholes did not have a significant influence on the temperature scaling. However, the staff does not consider this information sufficient to conclude that there were no signs of potential bed degradation. Please provide results of evaluation of the cause of the decreases in head loss that occurred during testing.

Dominion Response

It should be noted that while this response primarily addresses Rig 33 test results in response to the NRC's question, the Rig 89 test results for SPS 1 and 2 provide the design basis for the Dominion corrective actions that were implemented to address GL 2004-02. (See response to Question 4 below.)

Temperature/Viscosity Extrapolation (Rig 33)

The peak measured debris bed head loss in the reduced-scale test occurred four days after the first debris introduction. Using the peak measured debris bed head loss developed in many days in a thin-bed test to qualify short-term pump NPSH criterion has significant conservatism. In addition, this peak head loss occurred while the debris bed was still forming, prior to the time when any potential degradation might possibly occur. Another conservatism exists while scaling from test temperature to higher sump temperature. The debris bed will be less compact and more porous when the head loss is lower. The viscosity correction of head loss assuming the same compact debris bed is therefore conservative.

Recirculation Spray - In the reduced-scale test, the flow approach velocity to the strainer surface was calculated to be 0.0047 ft/s. With the test temperature (104°F) and flow condition, the test flow Reynolds number was approximately 3[1]. Hence, it was considered as laminar flow, where the NUREG/CR-6224 correlation shows that debris bed head loss is proportional to fluid viscosity.

A piece of debris bed removed from the strainer surface after the RS test is shown in Figure 3-2. No debris bed cracking, boreholes or degradation were observed.

An important conservatism in the temperature/viscosity extrapolation is that the peak head loss was used rather than a lower stabilized value.

Low Head Safety Injection - The SPS LHSI strainer Rig 33 reduced-scale thin bed test head loss curve is shown in Figure 3-3. No sudden head loss decrease was observed; hence, for this reason along with those mentioned above for the RS strainer, the viscosity correction method was applied for the LHSI strainer qualification.

Decreases in Head Loss (Rig 33)

As shown in Figure 3-1, the peak RS head loss occurred after the third fiber addition. After that, the head loss was in a slowly decreasing trend for a full day, with no sudden head loss decrease. The fourth fiber addition increased the head loss to 1.2 psi. Again, about 4 hours after the fourth fiber addition, the head loss decreased slowly again. The decreasing trends after the third and the fourth fiber additions were almost parallel, which indicated that the debris bed structure was consistent after the fourth addition.

A similar slow decrease in head loss was observed near the end of the Surry Rig 33 LHSI test, as shown in Figure 3-3. In the Surry Rig 33 reduced-scale testing, head loss increased until debris was removed from circulation. The gradual head loss decreases were assumed to have occurred after there was no more debris in circulation and the newly-formed debris bed was slowly settling into its final configuration.

As noted in the previous section, the head loss value taken from a test was the peak value, which occurred once all the debris had deposited onto the strainer.

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[1] $Re \equiv \rho VD / \mu$. The appropriate length, D, is the width of the flow passages between fibers. This has been taken as 1 mm, but could be significantly smaller. Velocity, V, is taken as the approach velocity to the debris bed, which is defined as the volumetric flow rate divided by the screen area. Assumed values are therefore: $\rho = 10^3$ kg/m^3, $V \sim 1.5\times10^{-3}$ m/s, $D \sim 10^{-3}$ m, $\mu \sim 5\times10^{-4}$ N.s/m^2, yielding Re ~ 3. This flow is fully laminar, and nowhere near the turbulent transition zone, which occurs around Re = 10^3.

Rig 89 Chemical Effects Tests

For long-term head loss, since the Rig 89 test temperature was the same as the long-term sump temperature, no viscosity correction was performed. No "sudden" head loss decreases were observed in Rig 89 testing before chemicals were added, as shown in Figure 3-4.

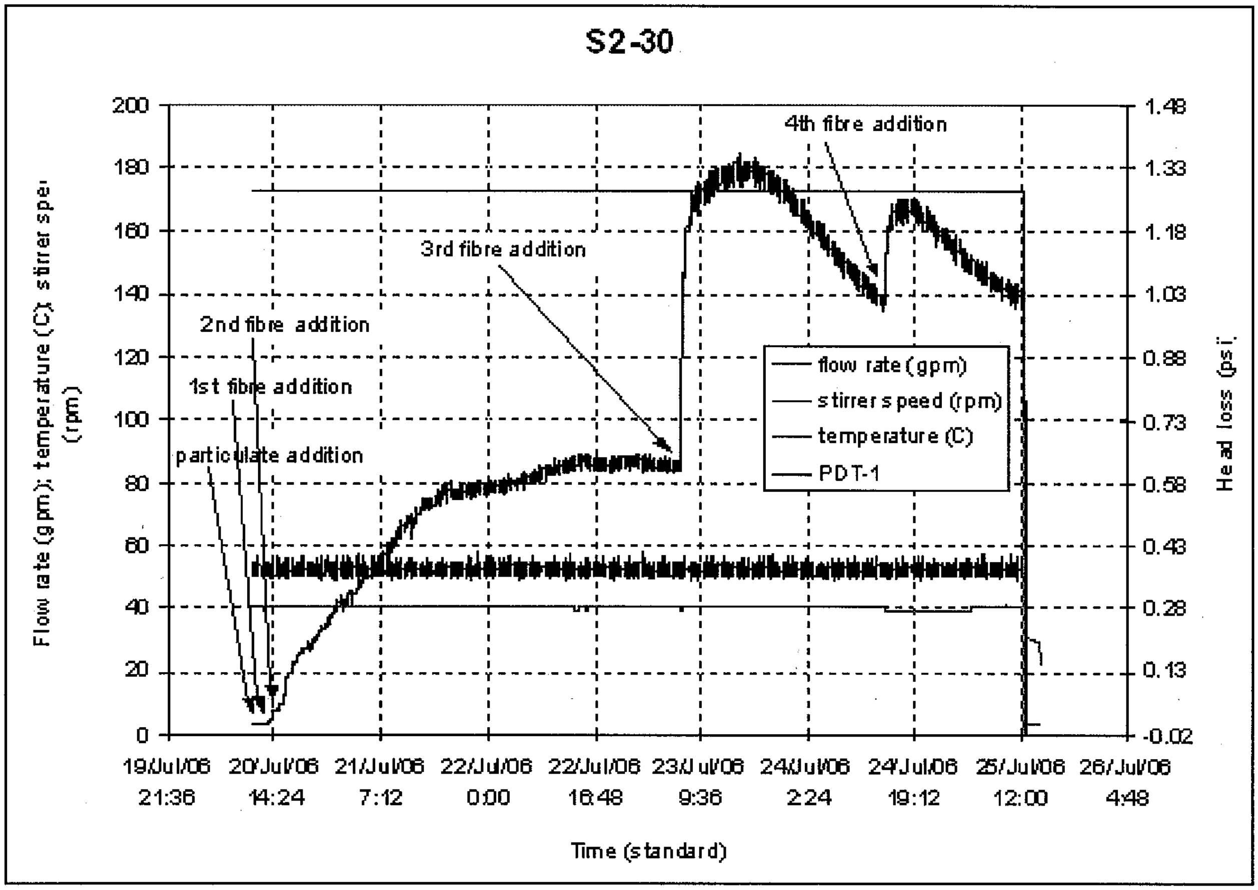


Figure 3-1: Test Parameters vs. Time for SPS RS Strainer Test

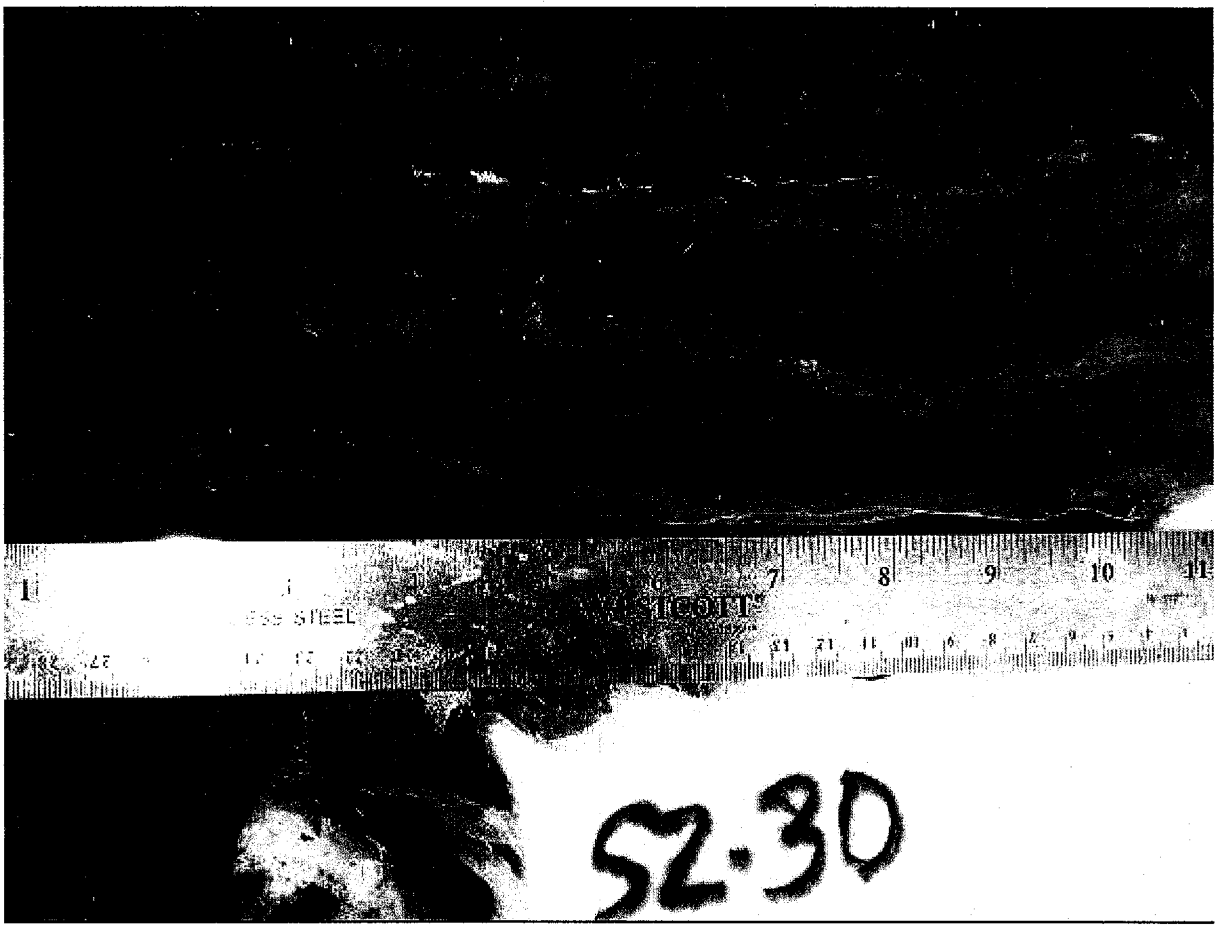


Figure 3-2: Debris bed Sample after SPS RS Strainer Test

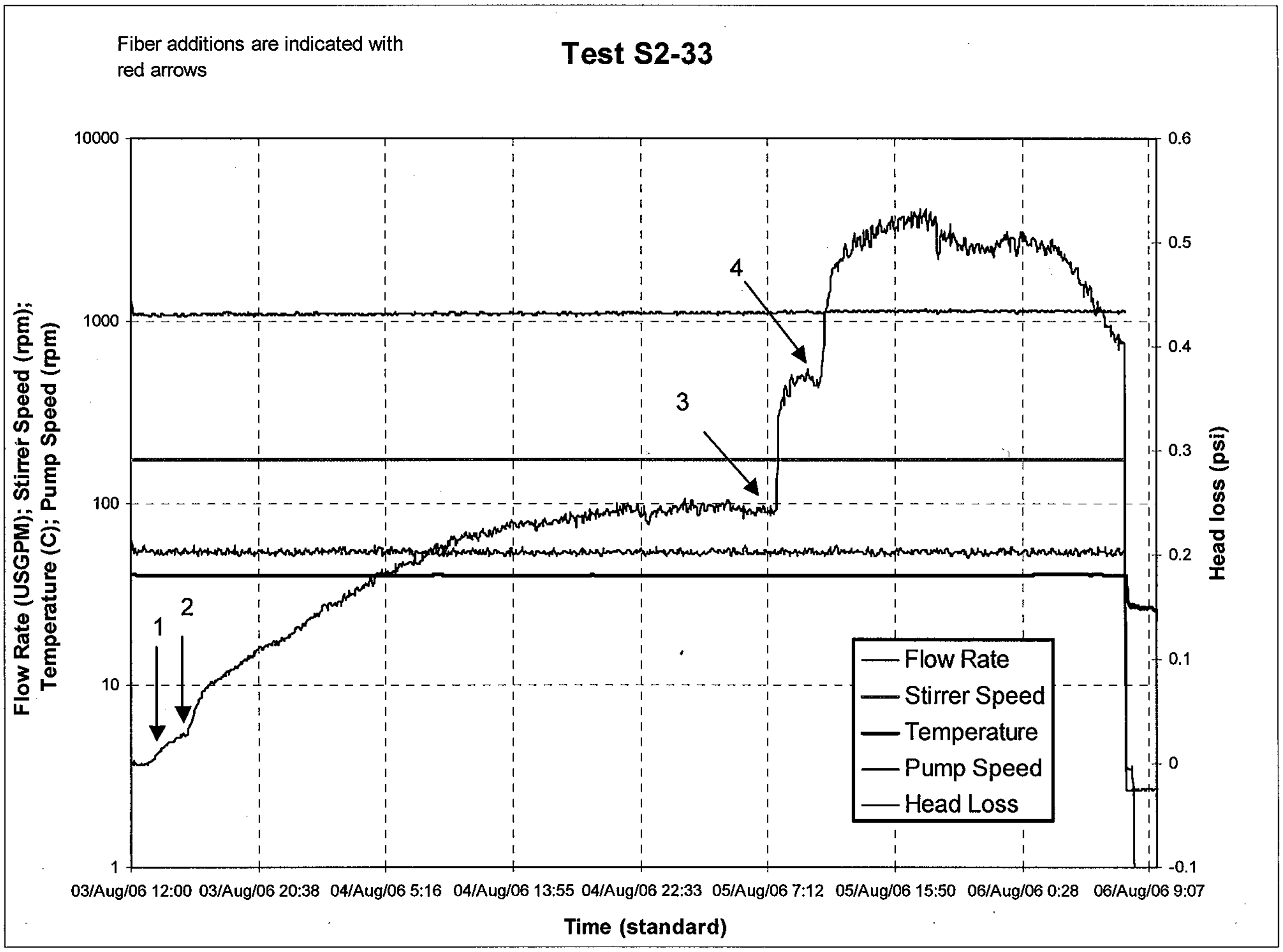


Figure 3-3: Test Parameters vs. Time for SPS LHSI Test

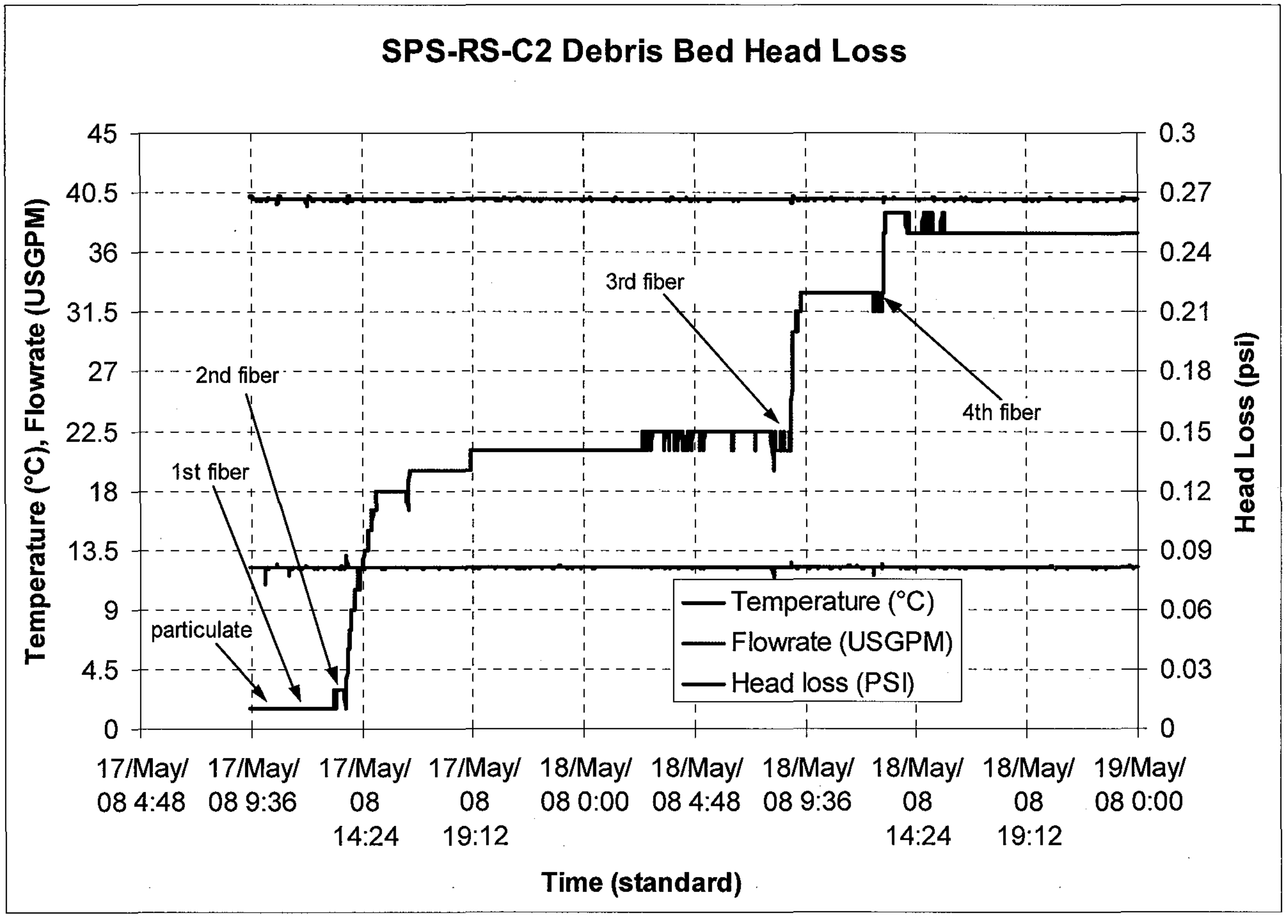


Figure 3-4: Surry RS Rig 89 Short-term Debris Bed Head Loss

NRC Question 4

Please provide an evaluation similar to that provided for North Anna to show that the results of both Rig 33 and Rig 89 tests, and the magnitude of plant-specific conservatisms for Surry, ensure that the strainers will function under design conditions.

Dominion Response

The differences in debris-only head loss testing results for the two different test rigs (Rig 33 and Rig 89) were evaluated during the North Anna Chemical Effects Audit performed by NRC staff in 2008 (Reference North Anna Power Station Audit Report dated February 10, 2009, ADAMS ML090410626). The NRC staff ultimately concluded that, although the reasons for differences in head loss for the two test rigs could not be definitively identified, the significant conservatisms incorporated into the sump strainer performance analysis bound the uncertainties associated with the different test results. A similar case can also be made for Surry sump strainer performance; however, a modification to the Low Head Safety Injection (LHSI) pumps will need to be implemented to retain the requisite margin to conservatively compensate for the different head loss testing results for the Rig 33 and Rig 89 test rigs. A discussion of the conservatisms associated with the Surry sump strainer performance analysis and the proposed LHSI pump modification is provided below.

Sections 1.a and 1.b of the Surry 2009 updated supplemental response dated February 27, 2009 (ADAMS ML090641018) describe the extensive plant conservatisms associated with the design of the containment sump strainer for each unit. Additional margins are discussed at the end of Section 3f in the Surry 2008 supplemental response dated February 29, 2008 (ADAMS ML080650562). A summary of these conservatisms is reiterated in the Safety Case provided in Attachment 2 to this letter. The overall magnitude of these conservatisms cannot be quantified; however, they are viewed to be significant, particularly for the factors listed below:

- 5% margin was added to the debris quantities generated from the ZOI.
- A sacrificial strainer area of 150 ft^2 was assigned for both the Recirculation Spray (RS) and LHSI strainer for each unit.
- 100% debris transport was assumed for coating and latent debris.
- In both Rig 33 and Rig 89 testing, fibrous debris was conservatively prepared as "single fine".
- The actual installed strainer area (effective) is larger than the test modeled strainer area as indicated in Table 4-1.

Table 4-1: Installed Strainer Area (effective) vs. Modeled Strainer Area

Station	Rig 33 Test Modeled Strainer Area (ft^2)	Rig 89 Test Modeled Strainer Area (ft^2)	Actual Installed Strainer Area (Effective)[1] (ft^2)
Surry 1 RS	5584	5310	5597
Surry 1 LHSI	2040	1814	2044
Surry 2 RS	5584	5310	5640
Surry 2 LHSI	2040	1814	2091

1) The actual installed strainer area (effective) equals the total installed strainer area minus the required sacrificial area of 150 ft^2.

Sump strainer reduced-scale thin bed tests were initially conducted in Rig 33 to determine the total strainer surface area for each station unit. Rig 89 test loops were used to investigate the influence of chemical precipitates on the debris bed head loss. The strainer supplier, Atomic Energy of Canada Limited (AECL), has prepared a detailed analysis report to evaluate the different results observed for the head loss tests performed in Rigs 33 and 89 [Reference 4.1]. The evaluation focused on the test rig configurations, flow patterns, debris compositions and quantities, debris preparation, air bubble generation, chemical environment, and debris bed formation. AECL and Dominion believe that the Rig 89 test results provide conservative evidence to verify that the installed strainer for each unit will function under short-term and long-term design conditions. Rig 89 tests incorporate lessons learned from the earlier Rig 33 testing, such as biological growth and testing fluid impurity, and consequently provide more accurate results. The AECL/Dominion testing program has concluded that the Rig 89 head loss test results are bounding and, furthermore, that test results from both rigs are conservative in that they produced higher head losses than predicted by NUREG/CR-6224.

Table 4-2 below compares the strainer debris head loss test results from Rigs 33 and 89 for debris only test configurations (no chemical effects). The short-term debris head loss acceptance criteria used for the strainer design bounds the non-chemical debris head loss test result from both Rig 33 and Rig 89. For evaluation of long-term pump NPSH margin, Surry confirmed that the Rig 89 test results with chemical effects met the long-term acceptance criteria for strainer head loss (long-term was defined as 4 hours to 30 days and includes the maximum effect of aluminium precipitation in the debris bed). In addition, it was noted that the differences in the non-chemical test results from Rig 33 and Rig 89 are much less than the long-term pump NPSH margins that were provided in Table 3.g-1 of the Surry February 27, 2009 supplemental response. The key design information from Table 3.g-1 is repeated in Table 4-3 below. Again, the minimum NPSH margin in Table 4-3 accounts for a total strainer design head loss that is bounding for Rig 89 test results including chemical effects. Furthermore, the outside RS and inside RS pumps have 10.3 ft and 12.5 ft of additional NPSH margin to cover the differences between Rig 33 and Rig 89 test results. The LHSI pumps have at least 8.5 ft of long-term NPSH margin. However, the NPSH available hydraulic calculation assumes that dissolved air released in the pump can is removed and that an adequate water level is maintained inside the pump can to ensure that the suction piping inlet nozzle is covered. The Surry RS pumps have air ejectors that prevent dissolved air in the suction flow from accumulating after it is released in the suction can. This ensures an adequate pump can water level that does not impose a constraint on the strainer head loss. In contrast, the LHSI strainer long-term head loss is limited to 2.2 ft (see Table 4-3) because of the LHSI pump design constraint resulting from previous removal of the LHSI pump can air ejectors. The design constraint is discussed below.

The Surry LHSI pumps are vertical, two-stage pumps that are located inside pump cans outside of the containment that are connected to the sump strainer by partially buried piping. For the available NPSH determination to remain valid, the water level inside each pump can must be maintained above the suction piping nozzle inlet to the can from the containment sump. Evaluations determined that the total LHSI strainer allowable head loss of 2.2 ft (Table 4-3) cannot be exceeded to ensure that the water level in the pump can remains above the suction pipe nozzle with adequate design margin. This limitation does not apply to the North Anna LHSI strainer as its associated pumps have air ejectors installed inside the pump cans to maintain a minimum pump can water level in the event air in the suction flow comes out of solution. Currently, the limiting head loss constraint imposed on the Surry LHSI strainer is from the pump can water level analysis. If this constraint is removed, the minimum NPSH margin of 8.5 ft shown in Table 4-3 is available for higher strainer head losses. This NPSH margin is more than adequate to accommodate the differences between Rig 33 and Rig 89 test results and test uncertainties.

To ensure the significant LHSI pump NPSH margin shown in Table 4-3 is available to accommodate potentially higher strainer head loss, SPS 1 and 2 will re-install air ejectors in the LHSI pump cans. This modification will ensure that the water level inside the can will remain well above the suction pipe nozzle, which will preserve the calculated NPSH margin shown in Table 4-3. The air removal design scheme and installed configuration will essentially be the same as the original LHSI pump design as well as that currently used for the Surry RS pumps. A refueling outage on each unit is required to install the modification, as each LHSI pump resides in an approximately 50 ft long pump can such that significant planning and coordination is required to facilitate removal of the pumps and installation of the air ejectors on the pump cans. The modification to install the air ejectors on the LHSI pump cans will be implemented during the fall 2010 refueling outage for Surry Unit 1 and the spring 2011 refueling outage for Surry Unit 2.

In summary, the Surry RS and LHSI strainers meet the short-term head loss acceptance criteria considering both Rig 33 and Rig 89 test results. The RS pumps have significant long-term NPSH margin to accommodate the difference in Rig 33 and Rig 89 test results and to cover test uncertainties. The Surry LHSI pumps have adequate long-term NPSH margin to bound the conservative Rig 89 test results. However, to ensure the long-term LHSI pump NPSH margin is available to accommodate Rig 33 head loss test results with significant margin, air ejectors will be added to the SPS 1 and 2 LHSI pump cans. The other strainer design conservatisms discussed above, and in the Safety Case provided in Attachment 2, provide the basis to conclude that the LHSI and RS strainers for SPS 1 and 2 will satisfy their design functions and accommodate the head loss differences observed between Rig 33 and Rig 89 test results with considerable margin.

Table 4-2: Rig 33 and Rig 89 Strainer Test Results – Debris Only

Strainer	Rig 33 Debris Head Loss (psid)	Rig 89 Debris Head Loss (psid)
LHSI	0.53 (Test S2-33) 0.24 (Test S2-35)	0.11 (Test SPS-LHSI-C1)
RS	1.0 (Test S2-28) 1.3 (Test S2-30)	0.26 (Test SPS-RS-C2)

Table 4-3: Summary of Long-term Pump NPSH Margins at Maximum Flow

Pump	Minimum NPSH Available [1] (ft H_2O)	Total Strainer Allowable Head Loss (ft H_2O)	NPSH Required (ft H_2O)	Minimum NPSH Margin[2] (ft H_2O)
Outside RS	24.48	5.0	9.19	10.29
Inside RS	28.0	5.0	10.5	12.5
LHSI	25.37	2.2	14.6	8.57

1) The minimum NPSH available accounts for all pump suction head losses except for the strainer.

2) Minimum NPSH Margin = Minimum NPSH Available – Total Strainer Head Loss – NPSH Required

Reference

4.1 AECL Analysis Report, GNP-34325-AR-001, Rev. 0; "Discussion of the Results of Head Loss Tests Conducted in Rigs 89 and 33."

NRC Question 5

The minimum strainer submergence was the same for both large-break and small-break loss-of-coolant LOCAs. It was not clear what sources were credited for the minimum level calculation. Please state whether the accumulators are credited for small break LOCA sump level calculations. If the accumulators are credited for small breaks, provide justification for this assumption, or provide the minimum water level if no accumulator volume is credited. Please state whether any RCS volume is credited for the minimum water level calculation. If RCS volume is credited, please provide the volume credited and the assumptions and bases for the credited volume.

Dominion Response

A single submergence value was reported for each strainer based on the more limiting minimum water level from small break LOCA (SBLOCA) and large break LOCA (LBLOCA) analyses. The basis for the minimum strainer submergence for both LBLOCA and SBLOCA is provided below. The available water sources include the refueling water storage tank (RWST), the chemical addition tank (CAT), the safety injection accumulators, and reactor coolant system (RCS) inventory released via the LOCA.

The LBLOCA minimum submergence values are 4.1" for the RS strainer and 8.2" for the LHSI strainer. These values are based on minimum water level calculations from GOTHIC NPSH transient analyses that include the holdup volumes discussed in the response to Question 7e. The LBLOCA analysis assumes that RS and LHSI recirculation begins with a +2.5% RWST wide range level bias (equivalent to 9738 gallons) on the plant setpoint, an initial RWST volume 3100 gallons below the Technical Specifications minimum, no contribution from the CAT, and initial empty containment sump. The accumulators inject fully before RS system actuation at 60% RWST level. Table 5-1 compares the LBLOCA containment sump water level to the strainer height.

Table 5-1: Comparison of LBLOCA Sump Water Level to Strainer Height

	Sump Level, inches	Strainer Height above floor, inches
IRS pump start at 62.5% RWST WR level	22.6	18.5
ORS pump start at 62.5% RWST WR level + 108 second timer delay	23.6	18.5
LHSI recirculation mode at 16% RWST WR level	49.2	41.0

The approach for determining the SBLOCA minimum water level was to identify differences from the LBLOCA response for SBLOCA scenarios that actuate the Consequence Limiting Safeguards (CLS), which initiates containment spray (CS) and RS on High High Containment Pressure. An accumulator volume of 2925 ft^3 (975 ft^3 each) is included in the LBLOCA response. Breaks smaller than 2" could reach RS actuation and LHSI switchover to recirculation before any accumulator injection occurs. Therefore, the accumulator volume is assumed unavailable for SBLOCAs. However, the accumulator volume is offset by sources of water that are not credited in the LBLOCA NPSH analysis but are credible sources for SBLOCA scenarios that have no accumulator injection.

- The LBLOCA analysis assumes 1720 ft^3 of water holdup in the refueling canal volume below the spillover elevation into the reactor cavity. Valves in the drain pipe from the refueling transfer canal to the containment basement are open during power operations. The only mechanism for holdup would be LOCA-induced debris clogging. Holdup was a conservative assumption for the NPSH analysis at project initiation. Later, it was concluded that the refueling canal drain would not be blocked by debris. All insulation in the spray region is jacketed with stainless steel, steam generator (SG) reflective metal insulation (RMI) large enough to affect the drainage does not have a transport path, and the only path for RCS loop piping insulation to reach the refueling canal is down to the sump and then through the recirculation spray system, which would limit the debris size to 1/16 inch (RS strainer hole size).

  The 3-inch refueling canal drain is located at the 6'10" elevation. The drain hole is open with no grating or mesh, so flow blockage would be required by a large piece of material. The Surry containment is compartmentalized with loop rooms, reactor coolant pump motor cubicles, and SG compartments that severely limit debris transport upward in the containment. To reach the refueling canal drain hole, debris would have to travel from the loop rooms (RCS piping is below the 15'5" elevation of the SG bottom support pad), vertically up through grating or around the supplemental neutron shield over the nozzles, through the SG compartment and over a 10 ft biological shield wall that extends to the 58'4" elevation, turn and travel horizontally to reach the narrow refueling canal opening at the operating deck (at 47'4" elevation), and bypass obstacles including the fuel upender cart and the manipulator crane that are parked over the drain and protect it from large particles. Spacing between the SGs and compartment floors is narrow and large pieces of RMI would be retained at lower levels below floors and grating. The SG structural supports provide additional restrictions to debris transport upward in containment. The refueling canal drain hole is large enough that credible debris generated by the LOCA that could reach the drain location would not impede drainage flow. Water holdup before flowing through the drain was calculated to be less than 3 ft^3, which is a small fraction of the available margins in the holdup on CS surfaces discussed in the response to Question #7. (See Table 7-1.)

- The LBLOCA analysis assumed 600 ft^3 of condensate films with 0.016-inch thickness on 450,000 ft^2 (11% above maximum design surface area) of containment heat structures as a constant throughout the NPSH analysis. Condensate films on heat sinks would not remain after containment spray actuates and the containment pressure decreases such that the passive heat structures become heat sources to the containment atmosphere. During small LOCAs with low steaming rates, the CS system rapidly depressurizes the containment before RS starts and condensate layers evaporate as the vapor temperature decreases below the heat sink surface temperature. The SBLOCA analysis does not include this penalty.

- The LBLOCA analysis assumes 200 ft^3 of water holdup in fibrous insulation in the sprayed regions. This insulation was jacketed with a design basis accident qualified jacketing system after the LBLOCA calculation was performed. The SBLOCA analysis does not include this penalty.

- The LBLOCA analysis ignores the contribution from the CAT (Technical Specification minimum volume of 3930 gallons), which is pumped by the CS system with RWST water such that the same relative water height is maintained in the tanks. At 60% RWST level, 40% CAT injection adds 1500 gallons (200 ft^3) to the RS strainer submergence. At 13.5% RWST level, 83% CAT injection adds 3300 gallons (440 ft^3) to the LHSI strainer submergence.

The above sources correspond to 2720 ft^3 of additional sump water before RS start and 2960 ft^3 before LHSI recirculation for SBLOCA scenarios. The volume for the LHSI strainer exceeds the accumulator volume of 2925 ft^3, and a minimum submergence of 8 inches is bounding for SBLOCA and LBLOCA. The volume for the RS strainer was 205 ft^2 (0.2 inch sump level) less than the accumulator volume. Accounting for this difference, the SBLOCA submergence is 3.9 inches versus 4.1 inches for LBLOCA. The minimum submergence was rounded down to 3 inches in Dominion letter serial number 08-0018, dated February 29, 2008.

If none of the above volumes were credited for SBLOCA, the LBLOCA submergence values would be reduced by 3.2 inches for the accumulators. There would be approximately 1 inch submergence for the RS strainer and 5 inches for the LHSI strainer. Strainer testing with no submergence and very conservative flow rates identified no air ingestion or vortexing.

The RCS contribution to the sump inventory was evaluated in terms of liquid mass rather than volume. The initial RCS liquid mass is 419,330 lbm. The hot leg double-ended guillotine break releases 283,230 lbm of RCS liquid to the containment through the end of the vessel reflood phase. At the end of reflood, the RCS contains 136,100 lbm of liquid. The RCS mass at the initiation of RS and ECCS recirculation is larger due to lower fluid temperatures in the vessel. The GOTHIC containment analysis model accounts for the temperature reduction as the containment and RCS are depressurized.

The RCS is also a source of water to the containment sump during SBLOCAs. For the RS system to receive an automatic start signal, the RCS must release a significant amount of steam to increase the containment pressure to the CLS actuation setpoint

(High High Containment Pressure). The RCS break must be large enough that safety injection system actuation does not prevent the RCS pressure from decreasing to the point at which the upper head and hot legs flash and the RCS water level drops to the elevation of the hot legs. The RCS mass releases to the containment are comparable to a LBLOCA release, but at a slower blowdown rate that is a function of the break size. Before the GSI-191 changes to the RS system actuation logic, the inside RS pumps started 2 minutes and the outside RS pumps started 5 minutes after the CLS signal. LOCA analyses that confirmed RS pump margins and performance requirements credited the RCS mass release to the sump. The GSI-191 change to start the RS pumps on 60% RWST wide range level coincident with a CLS signal confirmed that the SBLOCA RCS liquid mass release would be comparable to the large break LOCA before RS system automatic actuation.

To recover liquid inventory in the upper head, pressurizer, and steam generator tubes, the safety injection flow rate must be significantly greater than the core boiling rate and the break flow, and the steam in those volumes must be condensed via operator-controlled RCS depressurization and cooldown using secondary heat removal systems. Surry has high head safety injection (HHSI) and LHSI pumps, and accumulators that supplement RCS makeup at intermediate pressures. The HHSI pumps provide a flow rate that reaches equilibrium with and will eventually exceed the RCS break flow by a small amount. As noted, the HHSI flow alone is insufficient to recover liquid inventory in the upper head, pressurizer, and steam generator tubes. For a recovery of RCS inventory, operator action is required to depressurize the RCS below the accumulator injection pressure and below the LHSI pump injection pressure of 140 psig because the recovery requires the LHSI pump flow to supplement the HHSI pumps in establishing subcooled forced convection in the core. The cooldown and depressurization actions are governed by procedures that limit the RCS cooldown rate to 100°F/hr. Accumulator injection also acts to hold up RCS pressure, further slowing the cooldown (until the accumulators are procedurally isolated after the water is injected to minimize nitrogen intrusion). In addition, the upper head volume has a small flow area to the rest of the vessel, making it difficult to condense the steam in that volume (500 ft^3), which complicates pressurizer level recovery.

Figures 5-1 through 5-3 illustrate the system response described above for a 1.5" cold leg break. This is a near-limiting break size for RS strainer submergence for two reasons: 1) it provides a small RCS release path for evaluation of ECCS makeup capability and RCS liquid level recovery; and, 2) it results in a long time before reaching the CLS setpoint and RS actuation due to low steaming rates. These figures are from a SBLOCA design basis analysis that is documented in Chapter 14 of the Surry UFSAR. Figure 5-1 shows the pressurizer pressure drop rapidly until it stabilizes with the secondary system and then drops slowly due to the break. In Figure 5-2, the HHSI flow rate equalizes with the RCS break flow rate at about 8000 seconds, when pressurizer pressure is nearly 1000 psia (Figure 5-1). Figure 5-3 shows the total RCS mass approach 100,000 lbm at 8000 seconds. By this time, the RS system has started with an RCS mass contribution to the sump that is larger than the LBLOCA design case. Breaks larger than 1.5" were also evaluated and shown to support this conclusion.

For evaluation of the LHSI strainer, the most conservative scenario assumes that the RCS inventory is fully recovered before SI recirculation mode. This scenario is possible for very small breaks with a release that can be made up by the HHSI pumps at RCS pressures above the saturation pressure of the hot legs (such that no flashing occurs and RCS refill is single-phase). With a completely refilled RCS, the LHSI strainer has 1.1 inches of submergence (versus 8.2 inches for the LBLOCA) at recirculation mode transfer. With pressurizer level and subcooling restored, SI would be terminated and other plant systems (e.g., normal charging, residual heat removal) would be used for managing RCS inventory and heat removal. This transition is expected before reaching ECCS recirculation mode.

Figure 5-1: Pressurizer Pressure

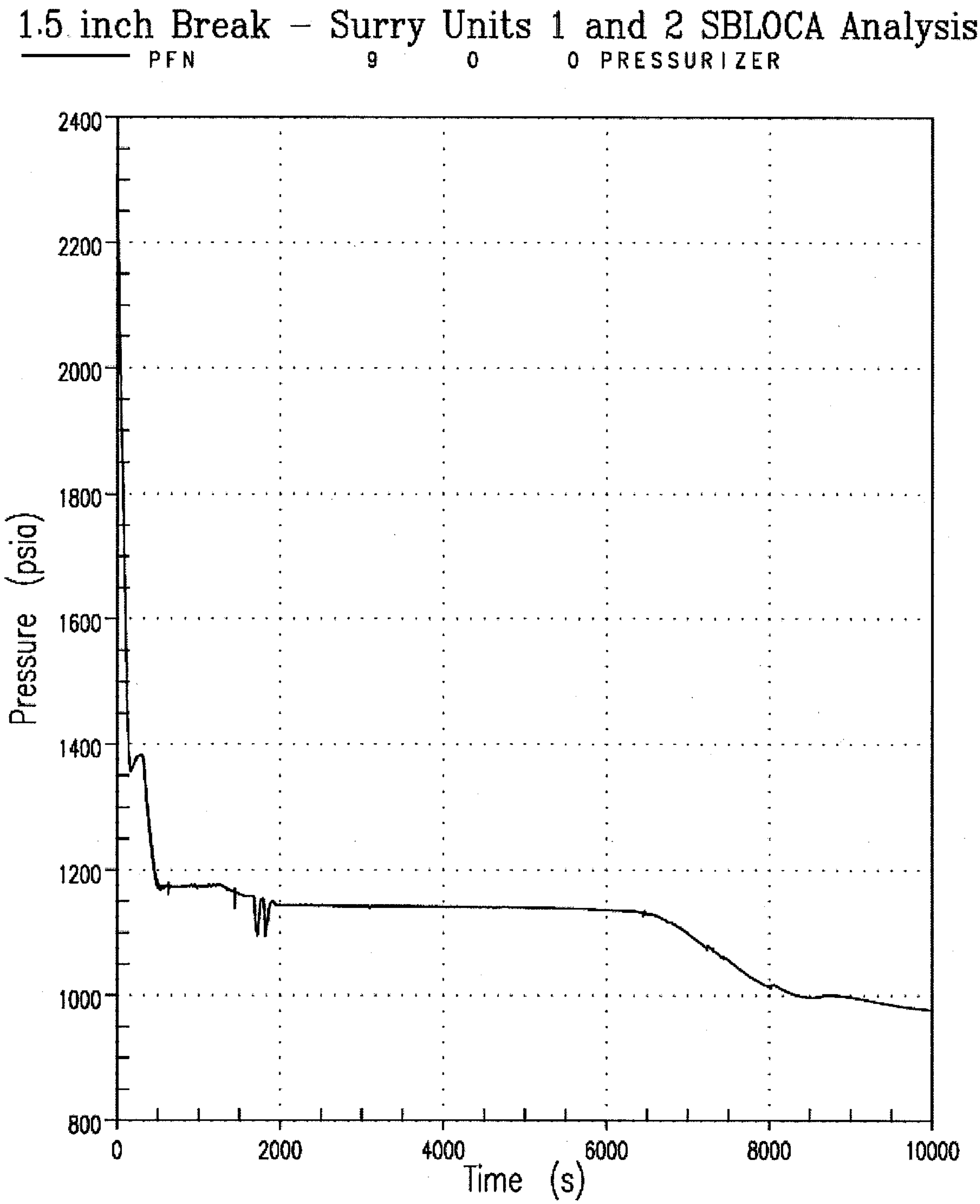


Figure 5-2: Comparison of Break Flow Rate (solid line) and the Total SI Flow Rate (dashed line)

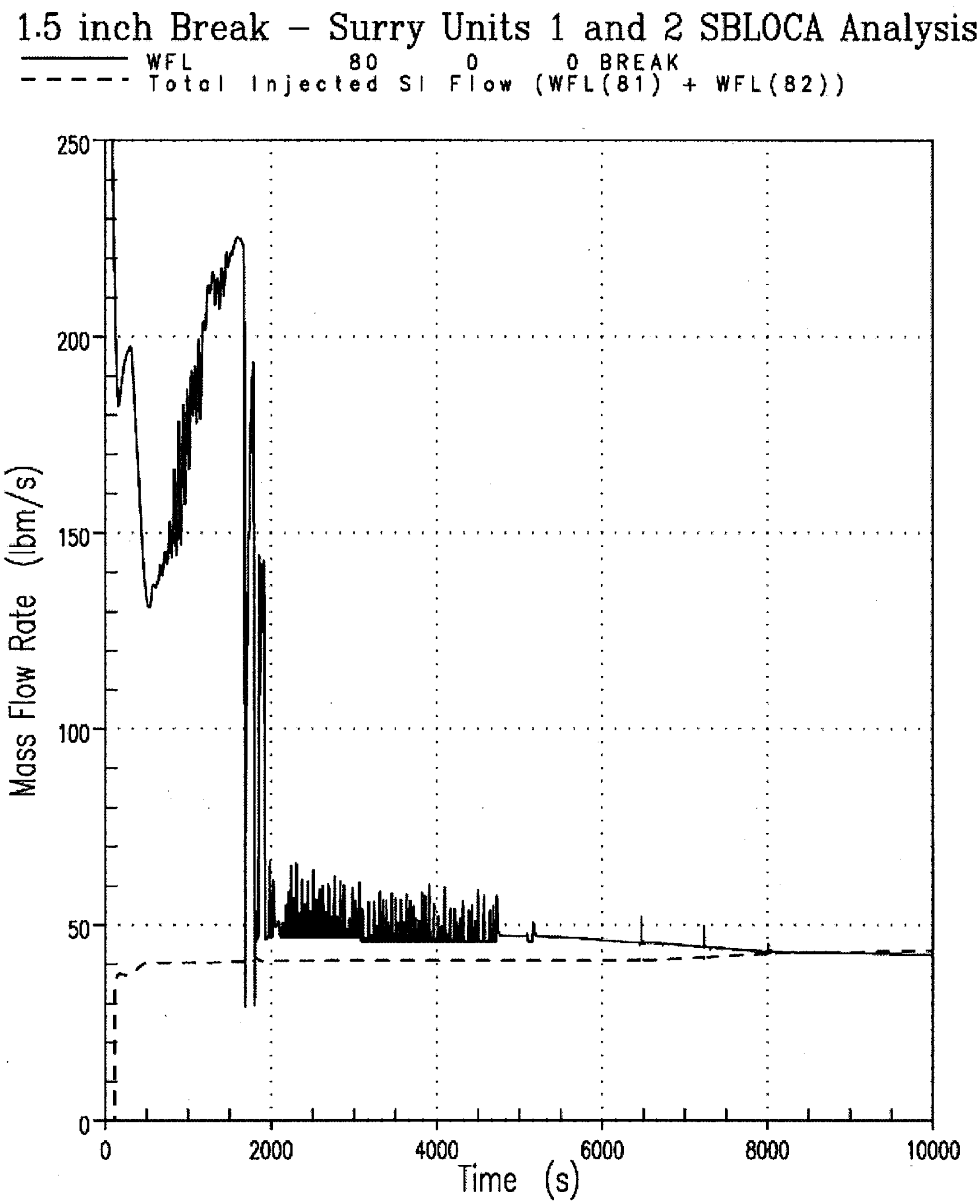
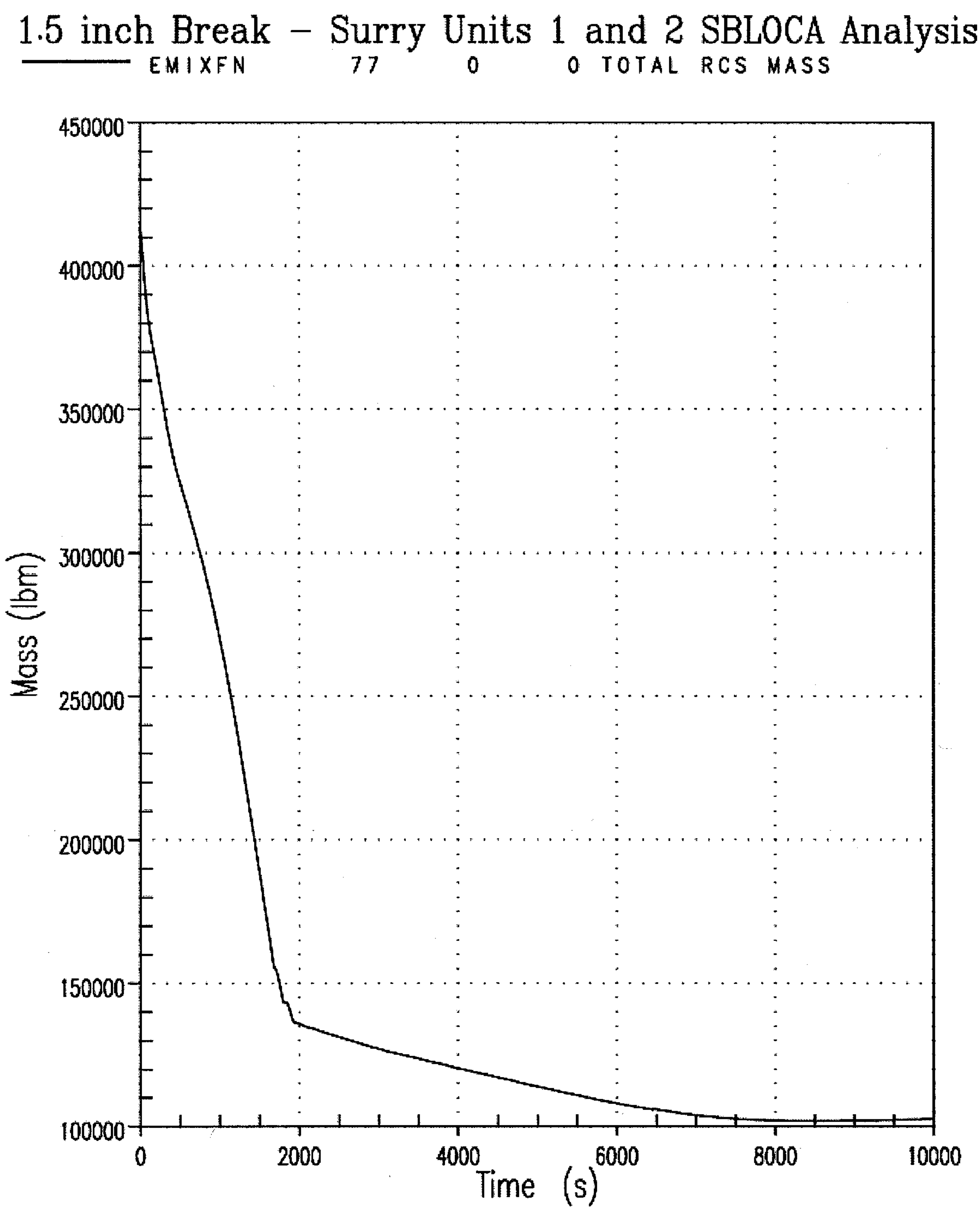


Figure 5-3: Total RCS Mass



NRC Question 6

Please provide an evaluation of the head loss fluctuations that occurred during the low-head safety injection (LHSI) Rig 89 testing between the 7th and 10th aluminum additions. Also, please explain why these fluctuations do not invalidate any viscosity corrections imposed on the test data.

Dominion Response

The head loss fluctuation between the 7th and the 10th aluminum additions during the Surry LHSI chemical effects testing is shown in Figure 6-1. As observed in the chemical effects tests, aluminum precipitate tended to deposit on the fiber surface and block the pores of the debris bed. At the time the 7th aluminum addition was added, the head loss was only 0.24 psi. Since the head loss was low, the debris bed was not tightly compact and it was fragile. As more aluminum precipitates deposited on the fiber surface, a dynamic process of debris bed cracking and self-repairing was initiated, which resulted in the head loss fluctuation. As more aluminum was added to the test tank, the head loss became higher and the debris bed was more densely compact and there was no fluctuation between the 11th and the 15th additions.

The peak measured head loss in the Surry LHSI strainer chemical effects test is 0.5 psi at 104°F, which occurred after the 15th aluminum addition. The long-term acceptance criterion for debris bed plus chemical effects (after subtracting allowance for analytically determined clean strainer head loss) is 1.41 feet of water at 104°F, which is equivalent to 0.61 psi at 104°F. Since the test temperature and the long-term sump temperature is the same, viscosity correction is not performed.

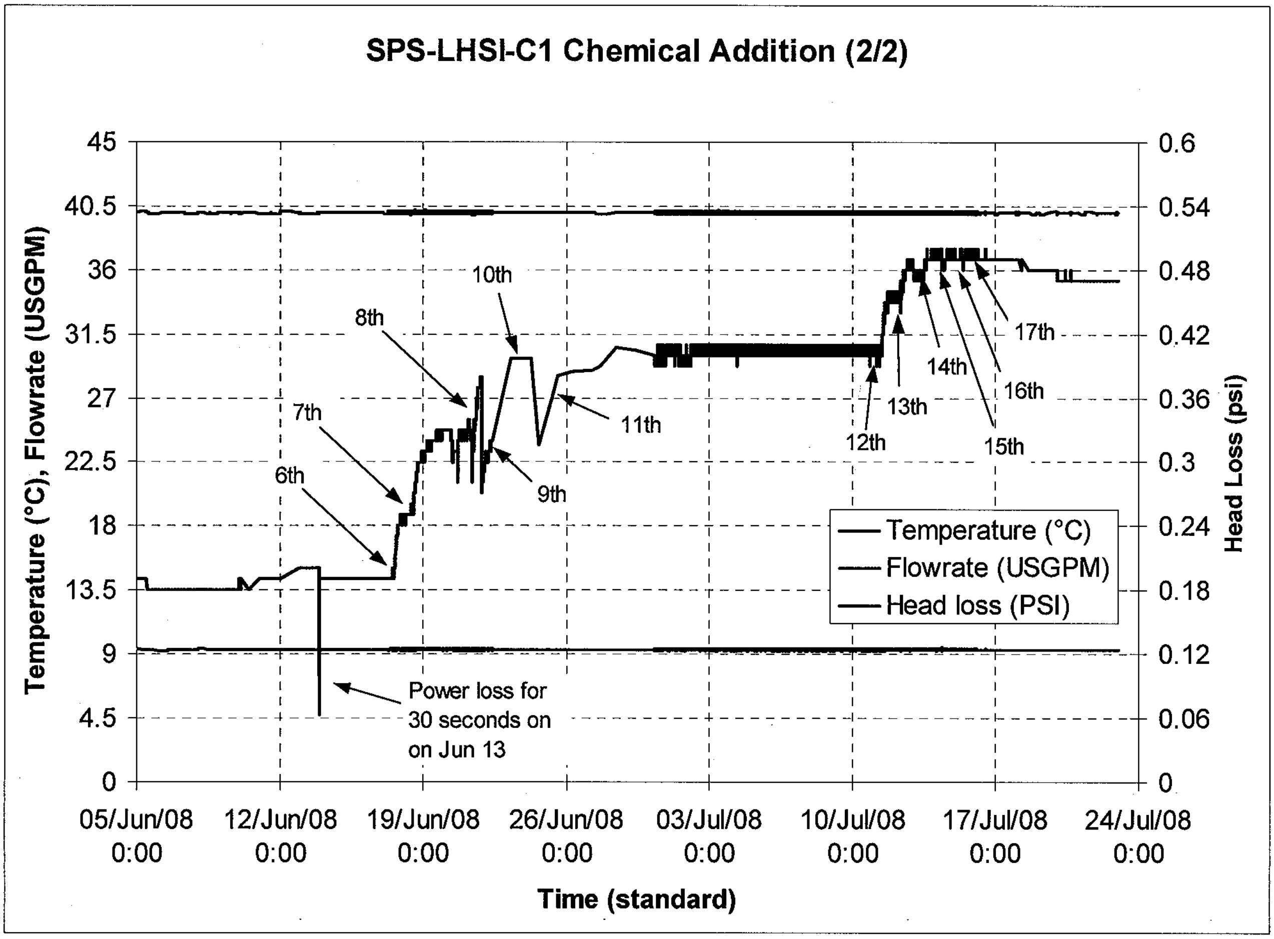


Figure 6-1: Head Loss Across the Surry LHSI Strainer during the Final Al Additions

NRC Question 7

The licensee's February 29, 2008, supplemental response indicated that the methodology for the Surry NPSH calculation was similar to that reviewed for North Anna during the GSI-191 audit for that plant. However, plant-specific differences and results for Surry were not provided in the supplemental response as requested in the NRC staff's content guide. Please provide the following information requested in the content guide. The responses may be in terms of stating that the same approach was used as for North Anna, or of describing any differences from the North Anna approach, which the NRC staff has already reviewed.

a. *a description of the methodology for computing the maximum flows for the LHSI and RS pumps*
b. *the basis for the required NPSH values, e.g., three percent head drop or other criterion*
c. *a description of how friction and other flow losses are accounted for*
d. *a description of the single failure assumptions relevant to pump operation and sump performance that were considered in the NPSH calculation*
e. *assumptions that are included in the analysis to ensure a minimum (conservative) water level is used in determining NPSH margin*
f. *a description of whether and how the following volumes have been accounted for in pool level calculations: empty spray pipe, water droplets, condensation and holdup on horizontal and vertical surfaces. If any are not accounted for, explain why*
g. *assumptions (and their bases) as to what equipment will displace water resulting in higher pool level.*

Dominion Response

a. *a description of the methodology for computing the maximum flows for the LHSI and RS pumps.*

The maximum pump flow rates for the LHSI, inside RS (IRS), and outside RS (ORS) pumps are calculated using hydraulic models of the system flow networks with the pump manufacturer's strongest pump curves and no debris on the strainers. The system hydraulic models account for the flow paths from the containment sump to the final injection point. For the RS system, the flow is discharged from the spray nozzles. For the LHSI system, the flow is discharged to the reactor coolant system cold legs during cold leg recirculation or the hot legs during hot leg recirculation. Conservative flow rates that bound the calculated flow rates from the hydraulic model are input to the GOTHIC analyses that determine minimum NPSH available (NPSHa). This same methodology was used to calculate the maximum LHSI and RS pump flow rates for North Anna.

b. *the basis for the required NPSH values, e.g., three percent head drop or other criterion.*

The pump required NPSH (NPSHr) values were reported in Table 3.g-1 of Dominion letter serial number 09-002, dated February 27, 2009. For the RS pumps, the manufacturer's pump curve includes a profile of NPSHr versus pump flow. The NPSHr curve from the manufacturer's original pump data sheet was superseded, because it was not based on a three percent head drop. Instead, it was based on lowering suction head until the NPSH was reduced to a minimum value provided in the original procurement specification. A review of the original test data revealed that the percent head drop was approximately one percent. To obtain additional margin, in 1977 Virginia Power conducted an NPSHr test at the North Anna job site with a pump with essentially identical hydraulic characteristics to the Surry RS pumps. The test results and the applicability for Surry are documented in an attachment to letter serial number 366 that was transmitted to the NRC on August 24, 1977.

For the LHSI pumps, the NPSHr curve from the manufacturer's pump data sheet was adjusted because the pump can and entrance losses were accounted for in both the NPSHr testing and in the system hydraulic model to determine NPSHa at the pump centerline impeller. Dominion documented the technical basis for the LHSI pump NPSHr value of 13.82 ft at 3330 gpm in a response to an NRC Request for Additional Information for the license amendments supporting the resolution of GSI-191. Refer to Question #2 in Attachment 2 of Dominion letter Serial No. 06-545 dated July 28, 2006 [ADAMS Accession No. ML062120719].

The basis for the NPSHr values reported in Table 3.g-1 of Dominion letter Serial No. 09-002 dated February 27, 2009 is a three percent drop in pump head observed during testing, which is consistent with the method used to determine the NPSHr values at the maximum pump flow rates for North Anna.

c. *a description of how friction and other flow losses are accounted for.*

The suction head losses were calculated for the LHSI, ORS and IRS pumps using the same hydraulic network analyses that determined the maximum pump flow rate. The head loss is converted to a loss coefficient for input to the GOTHIC containment model, such that the use of a bounding maximum flow rate in GOTHIC will scale up the head loss. The modeling of the suction hydraulic head losses in the GOTHIC containment model is described in Section 3.8.2 of Topical Report DOM-NAF-3, Rev. 0.0-P-A. The hydraulic network analysis that is used to determine the maximum friction and form losses and the application in the GOTHIC containment analyses are the same methodology as that applied for North Anna.

d. *a description of the single failure assumptions relevant to pump operation and sump performance that were considered in the NPSH calculation.*

The minimum NPSHa for the LHSI pump occurs for the single failure of an emergency diesel generator (EDG) that leaves one emergency bus powered to supply one LHSI pump and a train of RS (one IRS pump and one ORS pump) for containment heat removal. This scenario produces the maximum flow demand and NPSHr on a single LHSI pump and the largest suction piping friction loss to the pump, while providing only one train of containment heat removal that limits the sump temperature reduction before ECCS recirculation mode transfer. This single failure was confirmed to produce the minimum pump NPSHa by sensitivity studies using the GOTHIC analysis methodology. Dominion also evaluated the single failure of a LHSI pump. In this configuration, all four RS pumps and heat exchangers are available for sump cooling before recirculation mode transfer. The sump temperature is colder and the LHSI pump NPSHa is greater than the EDG failure case.

Dominion also evaluated scenarios with two LHSI pumps operating. The LHSI pumps have the same discharge header and the maximum system flow rate at cold leg recirculation is limited to 4100 gpm or about 2050 gpm per LHSI pump, which is 38% less than the single-pump flow rate of 3330 gpm. At 2050 gpm, the NPSHr is 10.0 ft, which is 3.82 ft lower than the single LHSI pump case (13.82 ft @ 3330 gpm). In addition, the individual pump suction piping head loss decreases from 6.66 ft at 3330 gpm to 2.52 ft at 2050 gpm. The reduction in NPSHr and suction piping head loss with two-pump operation provides 8 ft of NPSH margin that more than offsets the increase in strainer debris head loss from one-pump (3330 gpm) to two-pump operation (4100 gpm). In the LHSI strainer system, more than 75% of pressure losses occur in the branch line leading to the LHSI pumps and although the total strainer flow for the two-pump case is 23% greater (4100 gpm vs. 3330 gpm), the branch line flow for each pump is 38% less than the flow for a single-pump case. The single-pump case produces the maximum strainer branch line flow rate and head loss, the maximum total strainer head loss (debris plus internals), the maximum suction piping head loss, and the maximum pump NPSHr. Therefore, NPSH analyses with a single LHSI pump operating bound analyses for two-pump operation.

The analyses to determine minimum RS pump NPSHa included explicit analysis of single failures that can affect the containment response, including loss of one EDG, loss of an IRS pump, loss of an ORS pump, loss of a containment spray pump, and loss of a LHSI pump. In addition, a case with full engineered safeguards (no single failure) was analyzed. Section 3.6 in Attachment 1 of Dominion letter Serial No. 06-545 dated July 28, 2006, compared the results from the most limiting scenarios of no single failure, an EDG failure, and a LHSI pump failure. The loss of a single LHSI pump was limiting for the ORS pumps. The no failure case was the limiting NPSH scenario for the IRS pumps. Table 3.g-1 in Dominion letter Serial No. 09-002, dated February 27, 2009 documents the minimum RS pump NPSH margins based on the

GOTHIC NPSH analysis with the most limiting single failure. NPSH results are compared to the RS strainer head loss with four RS pumps at maximum flow in the short-term and two RS pumps at maximum flow in the long-term.

e. *assumptions that are included in the analysis to ensure a minimum (conservative) water level is used in determining NPSH margin.*

Section 3.8 in Topical Report DOM-NAF-3, Rev. 0.0-P-A, describes the GOTHIC analysis methodology for calculating NPSHa for the Surry LHSI and RS pumps. The use of this methodology for NPSHa analysis at Surry was approved by the NRC in a license amendment dated October 12, 2006 [ADAMS Accession No. ML062920499.] Section 3.8.3 in the topical report describes the water holdup terms that are included in the NPSHa analysis. These mechanisms include water added to CS and RS system piping, water trapped from transport to the containment sump in volumes (e.g., the refueling canal and reactor cavity), condensation films on heat structures, films on platforms and equipment that form after spray is initiated, and other losses (e.g., water absorbed in insulation). The GOTHIC containment liquid volume fraction is reduced by the total water holdup and then entered into a table of containment water level versus volume to determine the sump level that is used in the NPSHa calculation. GOTHIC explicitly models spray water droplets suspended in the atmosphere as a separate field that is not included in the containment liquid volume fraction that is used to determine the containment water level.

In addition, the Surry NPSHa analysis has other conservatisms that ensure a minimum water level is used: no contribution from the chemical addition tank; initial RWST volume of 384,000 gallons (versus Technical Specification minimum of 387,100 gallons); the containment sump is empty at the start of the LOCA (normal operation maintains approximately 500 gallons in the pit); and, +2.5% RWST wide range level uncertainty (9738 gallons) is applied in determining the initiation of RS and LHSI recirculation. Because the minimum NPSHa for the LHSI pump occurs right after recirculation mode transfer (RMT) to the sump, the assumption of 16% wide range RWST level versus the plant setpoint of 13.5% provides additional conservatism in the minimum water level calculation at RMT.

The same methodology was applied for the calculation of NPSHa for North Anna, but the Surry-specific holdup volumes are different due to plant geometry differences. Table 7-1 summarizes the holdup volumes in the Surry NPSHa analysis. The table footnotes describe conservatisms in the treatment of water holdup in insulation, as condensate films, and in the refueling canal.

Table 7-1: Summary of Holdup Volumes in NPSHa Calculation

Item	Volume, ft^3	Application
Refueling canal	1720	Fills after containment spray starts (note 1)
Reactor cavity	2480	Fills immediately to the elevation of the incore sump room drain (-25'7"); above -25'7" the water level versus volume table accounts for the open area inside the cavity wall
Films on heat sinks	600	Assumed from time zero (note 2)
Insulation	200	Assumed from time zero (note 3)
CS Piping	157 (A train) 220 (B train)	Assumed from time zero
RS Piping	815 (each IRS + ORS train)	GOTHIC volumes fill after RS pumps start
CS spray holdup	100	Platforms wetted by CS are assumed to be covered at time zero. This value is conservative compared to 68 ft^3 that was calculated.
RS spray holdup	400	Additional platforms are wetted when RS spray is delivered from nozzles; This value is conservative compared to 361 ft^3 that was calculated.

1) Valves in the drain pipe from the refueling transfer canal to the containment basement are open during power operations. The only mechanism for holdup would be LOCA-induced debris clogging, such that the volume below the spillover elevation into the reactor cavity is unavailable to the containment sump. This was a conservative assumption at the start of the GSI-191 project. Subsequent evaluation determined that there should be no debris blockage at the canal drain. All insulation in the spray region is jacketed with a qualified system, steam generator reflective metal insulation that would be destroyed by the RCS pipe break would not transport up through the SG cubicle to the canal, and the only path for RCS loop piping insulation to reach the refueling canal is through the recirculation spray system, which would limit the debris size to 1/16" (strainer hole size).

2) This holdup assumes a 0.016-inch thick film on 450,000 ft^2 (11% above maximum design surface area) of containment condensing heat structures throughout the analysis. Condensate films on heat sinks would not remain after containment spray actuates and containment pressure decreases such that the passive heat structures become heat sources to the containment atmosphere. Also, some condensing surfaces are double counted as spray holdup horizontal surfaces.

3) This value accounted for fibrous insulation in the sprayed regions that was jacketed with a design basis accident qualified jacketing system after the NPSH calculation was performed.

Also, Surry Procedures 1/2-MPT-1205-01, *Unit One/Two Containment Sump Inspection and Test Setup*, for SPS 1 and 2, respectively, require performance of a containment sump inspection. The procedures provide the instructions for assembly and closure of the containment sump with necessary controls to maintain the required Technical Specification containment sump cleanliness and restoration criteria during each refueling shutdown and/or after major maintenance activities in containment.

In addition to procedures 1/2-MPT-1205-01, unit startup procedures, 1/2-GOP-1.1, *Unit Startup, RCS Heatup from Ambient to 195 Degrees F,* require a containment readiness verification. The verification ensures containment is clear of debris such as plastic, tape, loose hardware or paper. The verification also requires that the containment recirculation sump and strainer are free of debris that could block the screened pipe nipples located near the bottom of the sump for each pump suction line.

f. *a description of whether and how the following volumes have been accounted for in pool level calculations: empty spray pipe, water droplets, condensation and holdup on horizontal and vertical surfaces. If any are not accounted for, explain why.*

The water level calculation includes all of these terms. The response to Part e above describes how the volumes are accounted for in the NPSH analysis.

g. *assumptions (and their bases) as to what equipment will displace water resulting in higher pool level.*

The relationship of containment sump water level versus volume of water accounts for the following: 1) the slope of the containment floor; 2) the geometry inside the sump pit; 3) displaced volume by equipment on the basement floor, including containment air cooling units and instrument air compressors and receivers; 4) water-tight structures, including structural columns, the reactor head storage stand, iodine filter fan stands, and the safety injection accumulators; and, 5) the primary shield wall and location of the incore sump room drain (see next paragraph). The minimum displacement volume of 174 ft^3 (between 6" and 41" above the containment floor) for the containment sump strainers was ignored in the NPSH calculation.

Once the water level reaches -25'7" elevation, the water level versus volume table is adjusted to account for the presence of the incore sump room drain that connects the reactor cavity to the outer containment basement. The additional surface area inside the reactor cavity is 620 ft^2. The incore sump room volume below -25'7" elevation is treated as a holdup volume that fills completely at the beginning of the LOCA (see Part e above).

NRC Question 8

Please provide a description of how permanent plant changes inside containment are programmatically controlled so as to not change the analytical assumptions and numerical inputs of the licensee analyses supporting the conclusion that the reactor plant remains in compliance with Title 10 of the Code of Federal Regulations *(10 CFR) 50.46 and related regulatory requirements.*

Dominion Response

Dominion has implemented a fleet GSI-191 Program as outlined in procedures CM-AA-CRS-10, *Containment Recirculation Sump GSI-191 Program*, and CM-AA-CRS-100, *GSI-191 Program Standards, Requirements, and Guidance for the Containment Recirculation Sump.* The fleet program designates a GSI-191 Fleet Lead and the Site Program Owners and delineates staff and management responsibilities to ensure the GSI-191 design and licensing bases and technical documents established for each site are properly maintained.

GSI-191 procedural controls have been developed and implemented for the engineering modification process. This process applies to both permanent and temporary modifications. Administrative procedures CM-AA-201, *Engineering Limited Scope Modification Process,* and CM-AA-DDC-201, *Design Changes*, establish the process for managing the preparation, processing, implementation, and organizational interfaces for design changes (DCs) to nuclear plant structures, systems, and components (SSCs). Plant modification engineering standards DNES-AA-GN-1003, *Design Effects and Considerations,* and STD-GN-0001, *Instructions for DCP Preparation*, provide guidance for performing required program reviews to: 1) verify compliance with regulatory programs, and 2) evaluate design and operational considerations to determine the acceptability of the activity being considered, including its effects on existing margins. The plant modification engineering standard includes a screening table to determine if the proposed change could affect the GSI-191 design basis. Specifically, the responsible engineer must answer a series of design effects questions. The GSI-191 design effects screening questions address the potential impact of the following in containment:

- Changes in fibrous materials,
- Addition of labels, stickers, or signs,
- Changes that impact a containment SSC design basis,
- Addition of significant horizontal or vertical surface area,
- Changes in unqualified or qualified coating inventories,
- Changes in chemical effects,

- Changes in downstream effects,
- Changes in post-LOCA water levels or recirculation flow paths, and
- Changes that modify the free volume or heat sink.

If the responsible engineer determines that the change could potentially affect the GSI-191 design basis, the potential impact must be evaluated by the GSI-191 Program Site Owner.

In addition to controlling the engineering modification process, procedural controls have been implemented for banned/restricted materials (e. g., aluminum), coatings, and insulation changes in containment. Procedure CM-AA-CRS-102, *Control of Aluminum and Banned/Restricted Materials Inside Containment,* has been implemented to outline the requirements and methods for controlling the use of aluminum inside containment in support of the GSI-191 design basis. This procedure provides requirements and establishes a mechanism for tracking the aluminum installed inside of containment for maintaining an aluminum inventory. The inventory, which is maintained by the GSI-191 Program Site Owner, provides the location and quantity of aluminum in containment and identifies whether the aluminum is subject to immersion or containment spray during DBA/LOCA accidents. The procedure requires the GSI-191 Program Site Owner to be notified of the changes.

In addition, Surry installation specification SUI-0009, *Installation Specification for Thermal Insulation,* has been updated to meet the requirements of GSI-191. Also, site administrative procedure VPAP-0905, *Insulation Control Program,* provides guidance for applying and replacing thermal insulation in containment. The procedure requires that the GSI-191 Program Site Owner be notified of the changes. The GSI-191 Program Site Owner maintains the insulation inventory.

The site installation coating specification NAS-3000/NUS-3003, *Installation Specification for Inside Containment Protective Coatings,* has been updated to be in alignment with the GSI-191 design basis for qualified coatings. Engineering coating standard DNES-AA-MAT-CTG-1001, *Criteria for Selection of Level 1 Coating Materials,* has also been implemented and provides criteria for selecting qualified coatings for inside containment. Level 1 coating requirements for procured equipment with protective coating to be installed inside containment are provided in engineering standard DNES-AA-MAT-CTG-1007, *Service Level 1 Coating Requirements for Procured Equipment to be Installed Inside Containment.* If a vendor component with an unqualified coating is considered for installation, the unqualified coating must be evaluated for GSI-191 design basis impact by the GSI-191 Program Site Owner.

In summary, the programmatic controls stated above ensure the GSI-191 design basis is being maintained effectively with respect to the plant modification process. To strengthen personnel awareness and understanding of the programmatic controls, training has been provided in the form of computer based training, engineering continued training, and GSI-191 related information bulletins.

NRC Question 9

Please provide a description of how maintenance activities, including associated temporary changes, that could affect the licensee's analytical assumptions and numerical inputs of the licensee's analyses relating to its resolution of sump performance issues, are assessed and managed in accordance with the Maintenance Rule, 10 CFR 50.65.

Dominion Response

Dominion has implemented procedure ER-AA-MRL-10, *Maintenance Rule Program,* for the performance of 10 CFR 50.65, Maintenance Rule (MRule), activities that require the licensee to assess and manage the risk associated with maintenance. The MRule Program implementing procedure ER-AA-MRL-100, *Implementing Maintenance Rule*, provides interface arrangements with other programs, such as the plant modification and preventive maintenance programs.

Changes to the design of an SSC are reviewed by the Design and System Engineers for potential impact on existing MRule functions, performance criteria, and unavailability limits in accordance with standards DNES-AA-GN-1001, *Engineering Review,* and DNES-AA-GN-1002, *Document Impact Summary*. This review is part of the program and design review for a permanent or temporary change. Associated design basis criteria are reviewed for impact from the proposed change.

Compliance with the MRule also includes the assessment of daily Condition Reports by the Maintenance Rule Site Owner, Engineering supervisors, and the Condition Report review team per procedure PI-AA-200, *Corrective Action*. The reviews ensure that reported issues are compared to the functions and performance criteria listed in the Maintenance Rule Function Scoping Matrix. Conditions that are potentially functional failures, or that challenge performance criteria or unavailability limits, are assigned to the System Engineer to perform a formal MRule evaluation.

As part of GSI-191 Program development, Dominion performed reviews of containment work orders for each of the Dominion nuclear plants. In all cases, the bulk of work activities that may have had an impact on the GSI-191 design basis were covered under the plant modification process. Only a small percentage of maintenance work order activities were identified to have potential GSI-191 design basis impact. Dominion has implemented procedure WM-AA-100, *Work Management*, that establishes the requirements for the work management process. Instructions are provided for complying with the requirements of the MRule Program. The Work Coordination Team (WCT) is required to review Work Orders on permanent plant SSCs for license renewal reliability concerns and potential operability or MRule concerns. The review considers engineering programs, including the GSI-191 Program. The WCT also reviews emergent work issues. The work order review process also covers specific program process controls established for coatings, insulation, and banned/restricted materials including aluminum.

In addition to the process controls discussed above, controls are in place for specific maintenance activities that could impact the GSI-191 design basis.

1. Dominion has established procedure CM-AA-CRS-103, *Containment Coating Condition Assessment,* to perform coating condition assessments of coatings inside containment. An unqualified coating inventory is maintained and updated each refueling outage. The inventoried quantity of qualified coatings in the worst case postulated LOCA pipe break location is also maintained. Changes to the qualified or unqualified coating inventories are evaluated to ensure the quantity of coatings assumed to fail post accident remains below the quantity of coatings analyzed for potential impact on the recirculation sump strainer.

2. Coating activities inside containment are controlled by site administrative procedure VPAP-0904, *Control of Protective Coatings.* Qualified coatings are applied by qualified applicators in accordance with the Level 1 application procedure CM-AA-CTG-101, *Coating Service Level 1 Application.* Coating applicators are qualified in accordance with procedure CM-AA-CTG-103, *Qualification of Service Levels I & III Coating Applicators and Surface Preparation Personnel.* For procured equipment with a protective coating that is to be installed inside containment, the coating must either be a qualified coating or evaluated for impact on the GSI-191 design basis as required by standard DNES-AA-MAT-CTG-1007, *Service Level 1 Coating Requirements for Procured Equipment to be Installed Inside Containment.*

3. Dominion procedure OP-AA-1200, *Equipment Labeling*, includes requirements for labeling equipment in containment. The procedure ensures that equipment labels placed in the reactor containment building are appropriate for the environment and will not adversely affect the recirculation sump strainer.

4. Surry administrative procedure VPAP-0905, *Insulation Control Program*, provides guidance for applying and replacing thermal insulation in containment. The procedure ensures the materials are appropriate for the containment environment and in compliance with the insulation specification. The GSI-191 Program Site Owner is required to evaluate insulation changes and the potential impact on the containment sump recirculation system.

5. Any material to be placed or remain in containment, that is not normally left in containment, must be evaluated by Engineering as part of an engineering process (i.e., Engineering Transmittal, Design Change Package, Limited Scope Modification, etc.) per standards DNES-AA-GN-1003, *Design Effects and Considerations,* and STD-GN-0001, *Instructions For DCP Preparation,* or by the

work order process by request to the engineering representative on the WCT in accordance with procedure WM-AA-100. If any equipment, supplies or materials are being considered for staging inside containment prior to cold shutdown or between outages (at power), approval must be obtained from the GSI-191 Program Site Owner.

6. Dominion implemented procedure CM-AA-CRS-101, *Latent Debris Collection and Sampling Procedure,* to perform periodic latent debris sampling in containment and to quantify the total latent debris in containment to ensure the quantity remains below the analyzed limit. During refueling outages, the Radiation Protection staff routinely performs cleaning of various areas in containment in accordance with Surry site procedure HP-1061.360, *Final Containment Washdown and Sump Decontamination.* Periodic wash down of containment also reduces the amount of latent debris in containment.

In summary, the procedural controls discussed above provide processes that allow Dominion to assess and manage maintenance activities inside containment that could impact the plant's GSI-191 design basis in accordance with the MRule Program.

NRC Question 10

Page 56 of 64 of the February 29, 2008 supplemental response indicates that the numerical data relating to the structural qualification of the replacement strainers is contained in two AECL Seismic Analysis Reports for Surry Power Station. In accordance with the second bullet in Section 3.k of the Revised Content Guide for Generic Letter 2004-02 Supplemental Responses, please provide and summarize, in tabular form, the design margins for the strainer components analyzed for structural adequacy.

Dominion Response

The structural design margins for SPS 1 and 2 strainer components are summarized in Tables 10-1 and 10-2. For components that could fail due to stress, the design margin is defined as:

Margin of safety = (Stress limit / Calculated stress) – 1

For components that could fail because of buckling, the design margin is defined as:

Margin of safety = (Calculated permissible pressure / Actual pressure) - 1

For both cases, as long as design margin is larger than zero, the component is structurally qualified.

The structural analysis of the strainer was conducted to meet the 1989 edition of ASME Section III, Subsection NF for Class 3 Component Supports.

Table 10-1: Margin of Safety – Surry 1/2 Strainer Headers

	Margin of Safety		
Component	**LHSI-RS Header**	**RS Header**	**RS Header with Single Sided Fins**
Header Bottom Plate	6.37	5.53	7.53
Header Top Plate	2.19	2.11	3.37
Vertical Deflector	2.54	2.33	5.64
Vertical Baffle	2.87	6.02	6.02
Horizontal Baffle	3.92	-	-
Channel	1.67	4.26	3.57
Fin Tab	2.51	2.1	24.4
Frame Bracket	0.85	2.07	5.15
Saddle Support	3.54	5.27	18.6
Top & Bottom Frames	9.98	17.1	40.8
Bolts in bottom plate/header support plate	0.44	1.36	-
Bolts in saddle vertical plate/anchor vertical plate	0.19	0.71	-
Bolts in frames and fins	5.73	20.8	12.6
Bolts in fin tabs	4.81	12.6	9.0
Bolts in frame brackets	9.67	3.2	13.4
End plate	1.87	2.32	-

Table 10-2: Margin of Safety – Surry 1/2 Pump Suction Headers

	Margin of Safety		
Component	**41-2-N**	**41-2-M**	**41-2-L**
Top plate	1.65	0.98	0.73
Bottom plate	1.18	0.55	1.68
Horizontal baffle plate	3.54	5.42	3.3
Side wall plate	1.13	1.77	1.91
Flange plate	5.62	-	-
Opening flange	1.55	-	-
Transition piece	-	3.99	3.92
Saddle support	-	3.62	-
Pipe	3.26	5.4	2.2

NRC Question 11

The NRC staff considers in-vessel downstream effects to not be fully addressed at Surry as well as at other PWRs. The licensee's submittal refers to draft WCAP-16793-NP, "Evaluation of Long-Term Cooling Considering Particulate, Fibrous, and Chemical Debris in the Recirculating Fluid." The NRC staff has not issued a final safety evaluation (SE) for WCAP-16793-NP. The licensee may demonstrate that in-vessel downstream effects issues are resolved for Surry by showing that the licensee's plant conditions are bounded by the final WCAP-16793-NP and the corresponding final NRC staff SE, and by addressing the conditions and limitations in the final SE. The licensee may also resolve this item by demonstrating without reference to WCAP-16793 or the staff SE that in-vessel downstream effects have been addressed at Surry. In any event, the licensee should report how it has addressed the in-vessel downstream effects issue within 90 days of issuance of the final NRC staff SE on WCAP-16793. The NRC staff is developing a Regulatory Issue Summary to inform the industry of the staff's expectations and plans regarding resolution of this remaining aspect of GSI-191.

Dominion Response

Dominion intends to address the in-vessel downstream effects issues by showing that SPS 1 and 2 are bounded by the final WCAP-16793-NP and the corresponding final NRC staff Safety Evaluation Report (SER) and that SPS 1 and 2 satisfy the conditions and limitations in the final NRC SER. Preliminary calculations and evaluations based upon Revision 0 of WCAP-16793-NP indicated that SPS 1 and 2 are bounded by the initial version of the WCAP-16793-NP and meet the draft conditions and limitations transmitted by the NRC to NEI. These preliminary calculations and evaluations were not finalized because of the subsequent Request for Additional Information by the NRC for completion of the review of WCAP-16793-NP. Preliminary evaluations have also shown that the Surry specific debris combination potentially reaching the core inlet is bounded by the fuel testing documented in Revision 1 of WCAP-16793-NP. Thus, Dominion expects to be able to finalize the calculations and evaluations and demonstrate the Surry is bounded by Revision 1 of WCAP-16793-NP and the corresponding final NRC staff Safety Evaluation and the conditions and limitations of the SER once the final NRC SER is issued. This will be confirmed and reported to the NRC within 90 days of issuance of the final NRC staff SE on WCAP-16793.

NRC Question 12

The licensee's letter dated February 27, 2009 states (page 39 of 43) that "a review of ICET results indicated minimal transport of aluminum surfaces sprayed for four hours, therefore it can be concluded that the aluminum released to the sump in the short term originates solely from submerged aluminum." On that basis, the licensee concluded that potential chemical effects during the first four hours after a LOCA would be insignificant. The NRC staff agrees that some corrosion product was retained on the sprayed aluminum samples in the relevant ICET tests. The staff, however, does not understand how this observation leads to the conclusion that the aluminum originated solely from the submerged aluminum coupons since the staff is not aware of how the measured dissolved aluminum concentrations could be apportioned into contributions from submerged and sprayed samples. Please provide the basis for this conclusion or provide alternate reasons (e.g., aluminum is more soluble at the higher pool temperatures present in the short-term following a LOCA) why the potential chemical effects are initially expected to be insignificant.

Dominion Response

Chemical effects in the short-term following a LOCA are expected to be insignificant on the basis that aluminum solubility exceeds the calculated aluminum concentration. Aluminum solubility in boron-containing solutions was reported by Bahn et al. [Reference 12.1] to be bounded by the equation below:

$$[Al]\ (\text{mg/L}) = \begin{cases} 26980 \times 10^{pH-14.4+0.0243T/^{\circ}F} & (\text{T} \le 175^{\circ}\text{F}) \\ 26980 \times 10^{pH-10.41+0.00148T/^{\circ}F} & (\text{T} > 175^{\circ}\text{F}) \end{cases}$$

Inputs to this equation include minimum sump pH and sump temperature.

Similar inputs are required to calculate aluminum release, though for conservatism the bounding maximum[2] sump and spray pHs have been used. To calculate aluminum concentration, the additional parameter of sump volume is required.

Using the following AECL aluminum release model,

$$\text{Release Rate (mg/m}^2\text{·s)} = 55.2 \cdot \exp\left(1.3947 \cdot pH - \frac{6301.1}{T}\right) \qquad \text{T in °K}$$

it can be seen in Figure 12-1 that the ratio of the predicted solubility to sump aluminum concentration reaches a minimum of 3.2 at short times (90-120 s) when the bounding

[2] Submerged aluminum release was calculated using the bounding maximum sump pH of 9.0. Sprayed aluminum release was calculated using the bounding maximum spray pH of 10.5 for the first 4 hours and 9.0 thereafter. Exposed aluminum release was calculated using a condensate pH of 7.0.

maximum temperature profile is used. At lower temperatures (Figure 12-2), aluminum release reduces drastically, and the ratio increases. The top curves of Figure 12-3 and Figure 12-4 indicate the temperature profiles used to calculate the aluminum concentration and solubility shown in Figure 12-1 and Figure 12-2, respectively, while the bottom curves indicate the temperature required to induce precipitation at the calculated sump aluminum concentration. In other words, if the sump temperature evolution followed the top curve but at some point cooled quickly, a temperature drop of 27°F or more would be needed to cause aluminum precipitates to form.

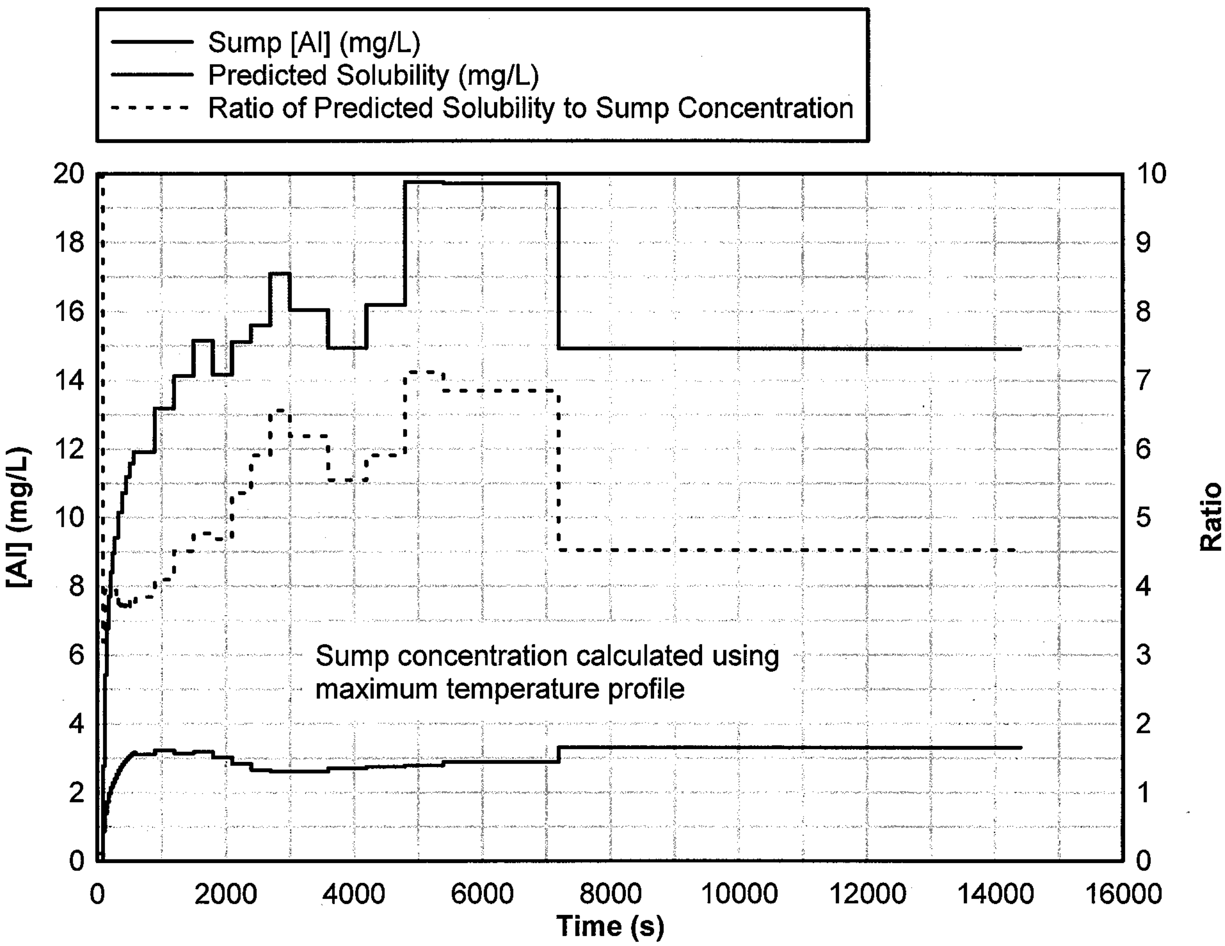


Figure 12-1: Ratio of aluminum solubility to predicted sump concentration using the bounding maximum temperature profile for Surry

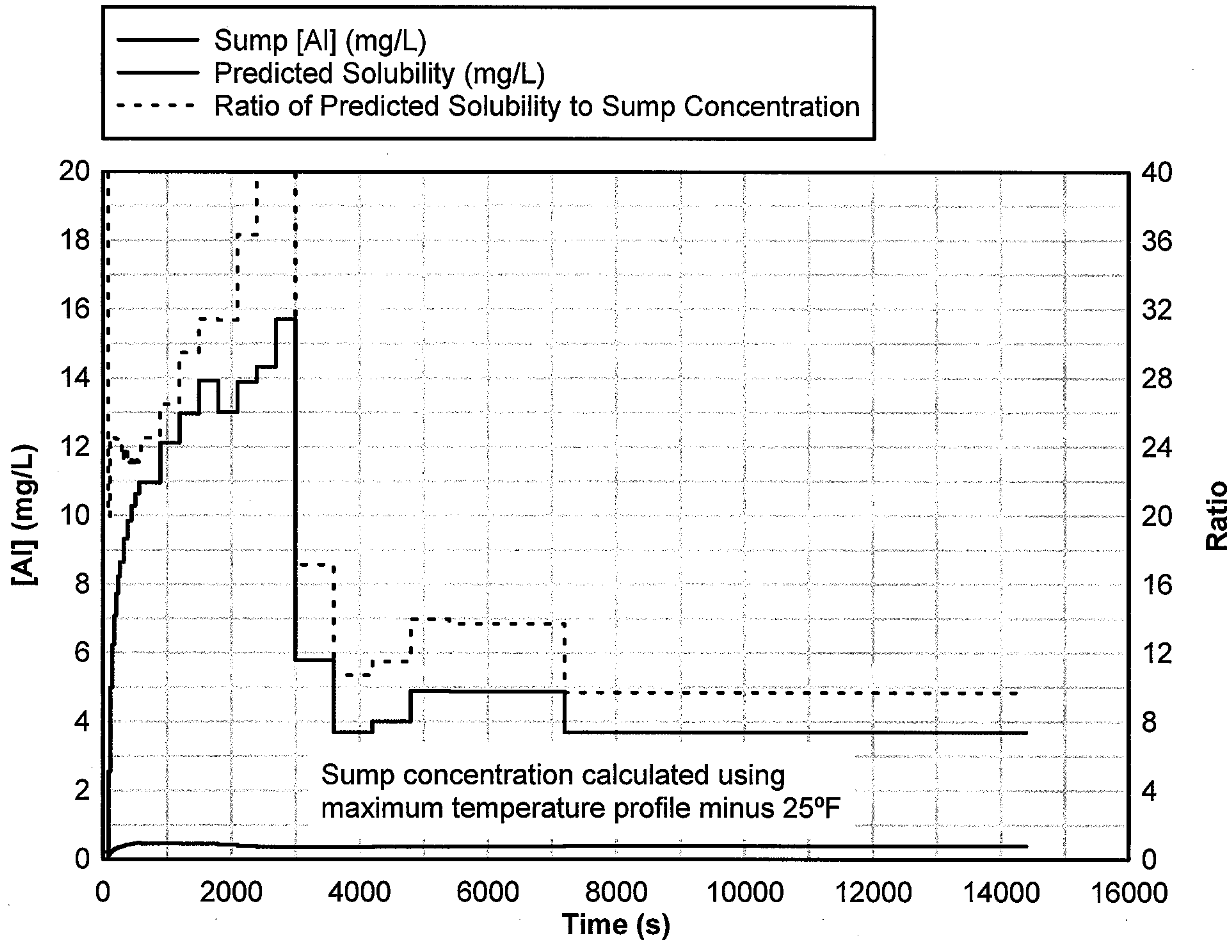


Figure 12-2: Ratio of aluminum solubility to predicted sump concentration using the bounding maximum temperature profile for Surry minus 25°F

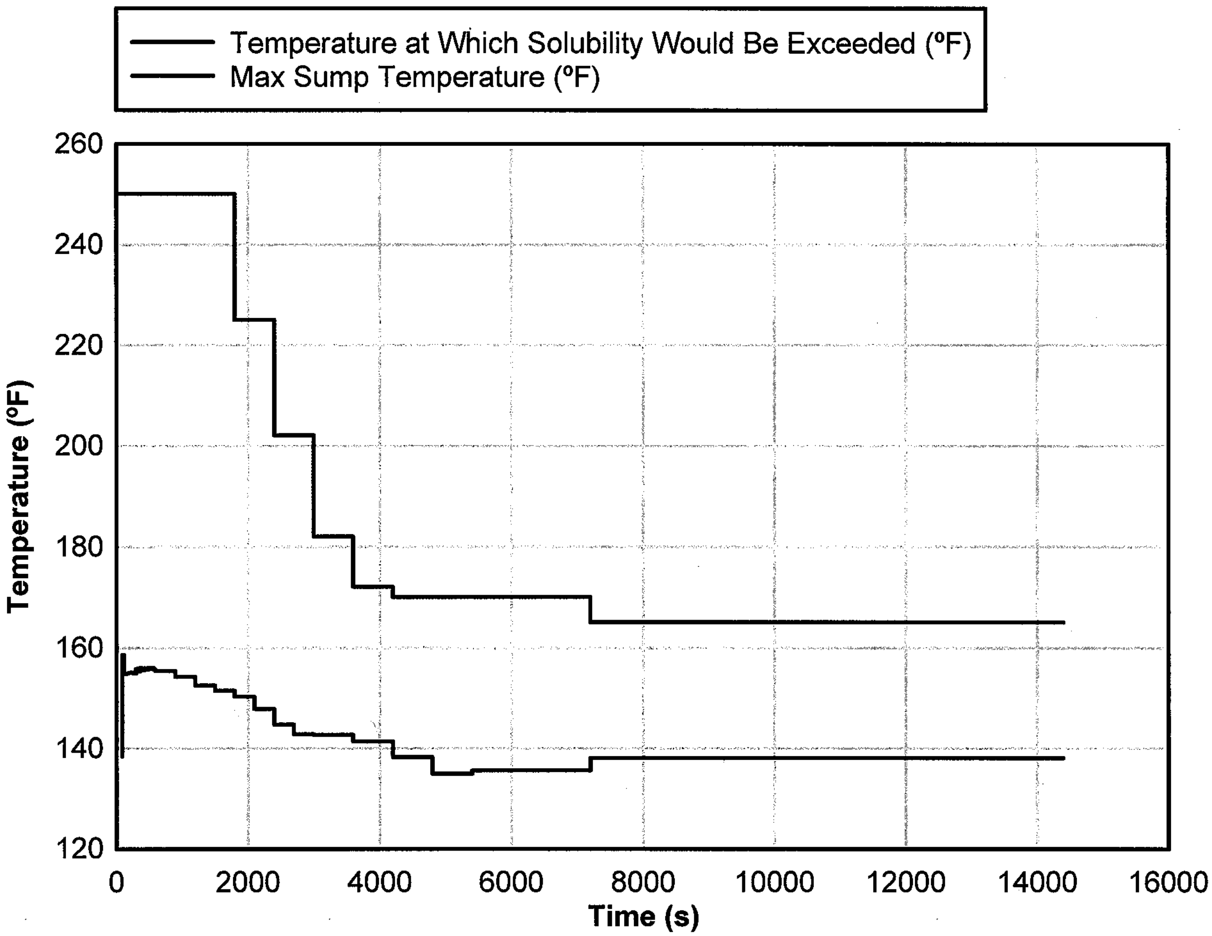


Figure 12-3: Bounding maximum temperature profile for Surry and the temperature to which the sump would have to drop in order to induce aluminum precipitation

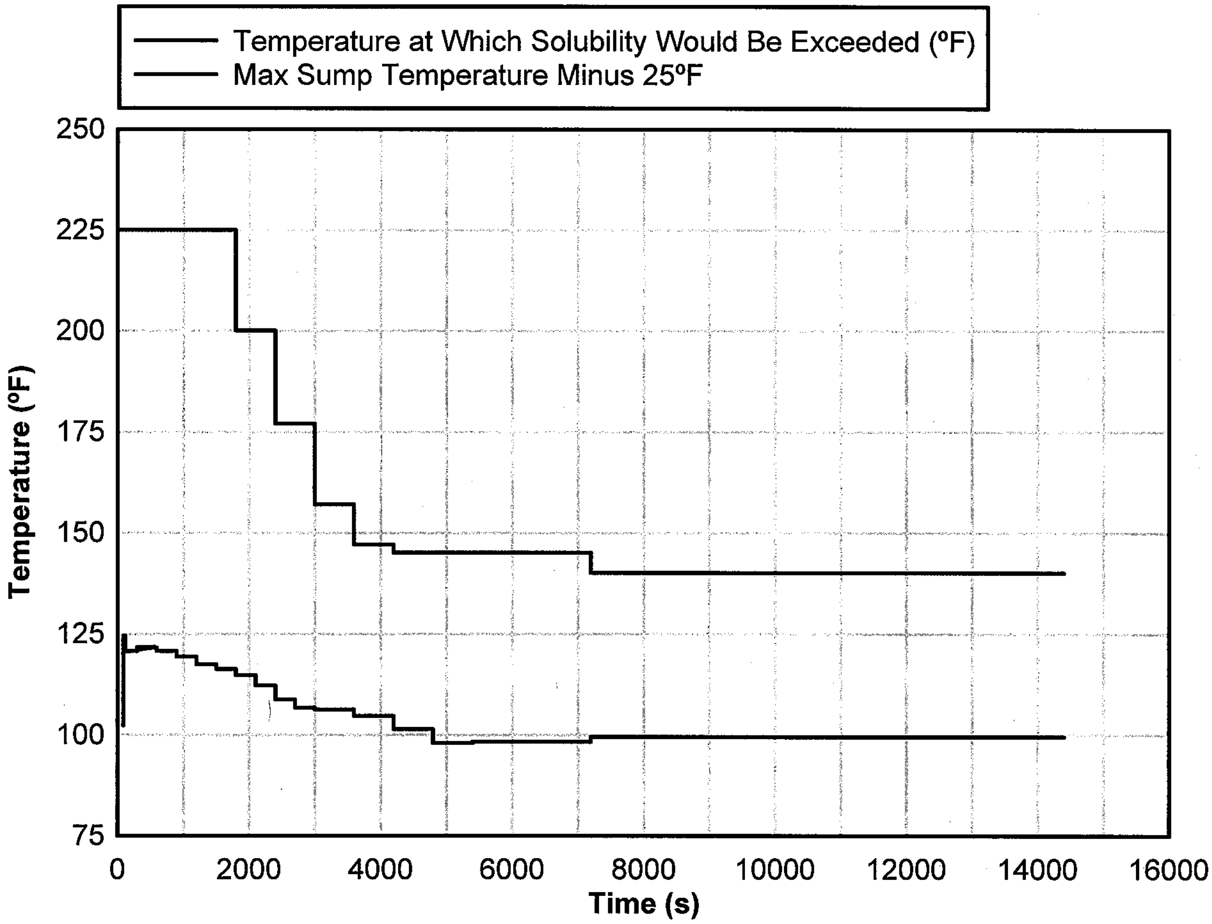


Figure 12-4: Bounding maximum temperature profile for Surry minus 25°F and the temperature to which the sump would have to drop in order to induce aluminum precipitation

Since chemical effects are expected to be insignificant in the short-term following a LOCA, based on the information and figures provided above, it may be reasonably concluded that chemical effects on strainer performance are expected to be insignificant in the short term following a LOCA, since no aluminum precipitation is predicted to occur in the first 4 hours.

<u>Reference</u>

12.1 C.B. Bahn, K.E. Kasza, W.J. Shack, K. Natesan, Aluminum solubility in boron containing solutions as a function of pH and temperature, Argonne National Laboratory, Argonne, IL; 2008 September 19. NRC Contract # J-4149.

NRC Question 13

Please describe how transported debris was assumed to be apportioned between the recirculation spray and LHSI strainers, and provide the basis for considering dual-train operation of the LHSI system to be bounded by single-train operation. With two LHSI pumps running, the total debris accumulating on the LHSI strainer would be greater, which in turn could result in an increased head loss that exceeds the conservatism associated with the NPSH evaluation for the single-train case under clean strainer conditions.

Dominion Response

RS Strainer:

The RS pumps take suction through the RS strainer prior to the LHSI pumps switching to recirculation mode. Therefore, the RS strainer could be exposed to 100% of the debris inventory. The RS strainer is assumed to be exposed to 100% of the LOCA debris load, as no time dependence is credited in the transport analysis.

LHSI Strainer:

The LHSI pumps transfer to cold leg recirculation mode after the RS pumps are already in operation. The conservative approach is to assume the debris transport to the LHSI and RS strainers is delayed until the LHSI pumps are switched to the recirculation mode. The transported debris is assumed to be homogeneously dispersed in the containment sump pool per NEI 04-07. Therefore, the debris will split between the LHSI and RS strainers based on the flow distribution to each strainer.

The LHSI strainer was tested with 40% of the full debris load. This is conservative for the limiting NPSH configuration of a single-train LHSI pump at maximum flow and two RS pumps at minimum flow with consideration of the RS pump suction injection flow rates. The minimum two-pump RS strainer flow rate is 5600 gpm based on two IRS pumps at a minimum flow rate of 3100 gpm each and 300 gpm recirculation flow from the discharge of the RS heat exchanger to the IRS pump suction. This is a continuous source of subcooling for IRS pump operation. During cold leg recirculation, the maximum single-pump LHSI strainer flow rate is 3330 gpm, which produces an LHSI strainer flow split of 37%. During hot leg recirculation (initiated 8.5 hours after the LOCA), the maximum flow rate increases to 3600 gpm with a LHSI strainer flow split of 39%. If two LHSI pumps are assumed to operate at 4100 gpm, the maximum flow split is 42% to the LHSI strainer.

The total amount of fibrous debris for LHSI strainer exceeded the theoretical thin bed thickness (1/4") amount. Since the bounding strainer head loss was based on thin-bed conditions, the greater amount of total fibrous debris had no influence on the tested head loss. The particulate debris amount would be increased by 5% ((42-40)/40) theoretically. Since the test modeled strainer area was smaller than the installed effective strainer area (1815 ft^2 vs. 2044 ft^2), when this fact was taken into consideration, the tested particulate debris amount was actually slightly higher than the particulate debris amount scaled from 42% of the full debris load.

The LHSI reduced-scale test flow rate was set to 9.32 gpm, which was scaled from one-pump flow of 3330 gpm. If scaled from two-pump flow of 4100 gpm, by using the installed effective strainer area, the test flow rate would be 10.19 gpm. Higher flow rate would result in a more compacted debris bed. By conservatively assuming head loss is proportional to the square of the approach velocity, the impact of compaction/ compression of debris could be covered. Previous Surry LHSI flow sweep testing indicated that the head loss was proportional to the power of 1.7 of the approach velocity. Using the quadratic relationship, the head loss would be 19.5% higher than the test result $((10.19 / 9.32)^2)$. Applying the approximately 20% increase to the short-term and long-term LHSI debris bed head loss, the net head loss increases would be 0.04 ft for short term and 0.23 ft for the long term. This increase is negligible compared to the much greater gains in allowable strainer head loss for two-pump operation as compared to one-pump operation.

It was concluded that the small increase in LHSI strainer debris head loss for a 2% increase in the flow split (versus the 40% debris that was tested) would be well bounded by the NPSH analysis for one-pump operation. The basis demonstrating single-train LHSI operation significantly bounds two-train operation for determination of NPSH margin is provided in the response to Question 7d above, from which the following information is repeated.

The LHSI pumps have the same discharge header and the maximum system flow rate at cold leg recirculation is limited to 4100 gpm or about 2050 gpm per LHSI pump, which is 38% less than the single-pump flow rate of 3330 gpm. At 2050 gpm, the NPSHr is 10.0 ft, which is 3.82 ft lower than the single LHSI pump case (13.82 ft @ 3330 gpm). In addition, the individual pump suction piping head loss decreases from 6.66 ft at 3330 gpm to 2.52 ft at 2050 gpm. The reduction in NPSHr and suction piping head loss with two-pump operation provides 8 ft of NPSH margin that more than offsets the increase in strainer debris head loss from one-pump (3330 gpm) to two-pump operation (4100 gpm). In the LHSI strainer system, more than 75% of pressure losses occur in the branch line leading to the LHSI pumps and although the total strainer flow for the two-pump case is 23% greater (4100 gpm vs. 3330 gpm), the branch line flow for each pump is 38% less than the flow for a single-pump case. The single-pump case produces the maximum strainer branch line flow rate and head loss, the maximum total strainer head loss (debris plus internals), the maximum suction piping head loss, and the maximum pump NPSHr. Therefore, NPSH analyses with a single LHSI pump operating bound analyses for two-pump operation.

To maintain the plant configuration consistent with the above design assumptions, the Emergency Operating Procedures maintain at least two RS pumps in service during the long-term recovery following a LOCA.

ATTACHMENT 2

Safety Case Demonstrating Overall Compliance with the Applicable Regulations Specified in GL 2004-02

VIRGINIA ELECTRIC AND POWER COMPANY
(DOMINION)
SURRY POWER STATION UNITS 1 AND 2

Safety Case Associated with the Implementation of Corrective Actions to Address the Sump Performance Issues Discussed in GL 2004-02

Surry Power Station Units 1 and 2

By letters dated February 29, 2008, (ADAMS ML080650562) and February 27, 2009 (ADAMS ML090641018), Dominion provided supplemental responses to Generic Letter (GL) 2004-02, "Potential Impact of Debris Blockage on Emergency Recirculation during Design Basis Accidents at Pressurized-Water Reactors," for Surry Power Station (Surry) Units 1 and 2. In these two responses, Dominion provided detailed information regarding the analyses and modifications that it has performed to demonstrate that there is reasonable assurance that Surry Units 1 and 2 can provide long-term cooling of the reactor core following a design basis accident (DBA). Based on the information provided in these letters and the results of additional activities that have been completed since their submittal, a safety case has been prepared delineating the analyses and modifications that have been performed, and the significant conservatisms that have been incorporated, to demonstrate that Dominion has appropriately and conservatively addressed the sump performance issues discussed in GL 2004-02 for Surry.

Methodology of Analyses

The potential for adverse effects of post-accident debris blockage and debris-laden fluids to prevent the recirculation functions of the Emergency Core Cooling System (ECCS) and the Containment Spray Systems (CSS) [i.e., the Containment Spray (CS) and Recirculation Spray (RS) systems] was evaluated for Surry Units 1 and 2. The evaluation considered postulated design basis accidents for which the containment sump recirculation mode of these systems is required. Mechanistic analyses supporting the evaluation satisfied the following areas of the NRC approved methodology in the Nuclear Energy Institute (NEI) 04-07, "Pressurized Water Reactor Sump Performance Evaluation Methodology" Guidance Report (GR), as submitted by NEI on May 28, 2004, as modified by the NRC Safety Evaluation (SE), dated December 6, 2004:

Break Selection
Debris Characteristics
Debris Transport
Vortexing
Debris Source Term
Upstream Effects
Debris Generation and Zone of Influence
Latent Debris
Head Loss
Net Positive Suction Head Available
Structural Analysis

Detailed analyses of debris generation and transport ensure that a bounding quantity and a limiting mix of debris are assumed at the containment sump strainer following a DBA. Using the results of the analyses, conservative evaluations and strainer testing were performed to determine worst-case strainer head loss and downstream effects. Chemical effects bench-top tests conservatively assessed the solubilities and behaviors of precipitates and applicability of industry data on the dissolution and precipitation tests of station-specific conditions and materials. Reduced-scale testing was performed by Atomic Energy of Canada Limited (AECL) using two separate test facilities: Test Rig 33, a single-loop test rig, and multi-loop Test Rig 89. The multi-loop testing established the influence of chemical products on head loss across the strainer surfaces by simulating the plant-specific chemical environment present in the water of the containment sump after a LOCA.

Modifications

Numerous plant modifications associated with GL 2004-02 to resolve NRC Generic Safety Issue (GSI) 191, "*Assessment of Debris Accumulation on PWR Sump Performance,*" have been completed for Surry Units 1 and 2 including the following:

1. New containment sump strainers (with corrugated, perforated stainless steel fins) were installed in the containment sump for Surry Units 1 and 2. The total effective surface area of the Unit 1 RS strainer is approximately 5597 ft^2, and the total effective surface area of the Low Head Safety Injection (LHSI) strainer is approximately 2044 ft^2. The total effective surface area of the Unit 2 RS strainer is approximately 5640 ft^2, and the total effective surface area of the Unit 2 LHSI strainer is approximately 2091 ft^2. These strainers replaced the previous screens, which had a surface area of approximately 158 ft^2.

2. A drain was drilled in the Primary Shield Wall of the Incore Sump Room to reduce the water holdup volume and increase the total volume of water available for recirculation.

3. Engineered Safeguards Features (ESF) circuitry was added to start the RS pumps on a Hi-Hi Containment Pressure Consequence Limiting Safeguards (CLS) signal coincident with a Refueling Water Storage Tank (RWST) Level Low signal. The Inside RS (IRS) pumps receive an immediate start signal once the coincidence logic is satisfied. The Outside RS (ORS) pumps start following a timer delay of 120-seconds once the coincident logic is satisfied. These changes ensure sufficient water is available to meet the RS strainer submergence and RS pump net positive suction head (NPSH) requirements.

4. Insulation inside the containment that could contribute to spray or submergence-generated debris that was found to be damaged, degraded or covered with an unqualified jacketing system was removed or jacketed with a jacketing system qualified for a DBA.

5. The containment sump level transmitters were modified to protect them from clogging due to debris. Specifically:

   - Level transmitters located within the sump have been modified by drilling holes through stilling wells at various places to prevent the element from clogging, and

   - Level transmitters located above the containment floor have been provided with debris shields to protect them from containment spray generated debris.

In addition to the modifications listed above, the following actions have also been completed:

1. Completed analysis of water hold-up in containment to identify locations where water will be blocked from reaching the RS and LHSI strainers.

2. Revised the Surry Units 1 and 2 Technical Specifications (TS) to increase the containment air partial pressure limits to provide analytical margin, including NPSH margin for the RS and LHSI pumps. The TS were also revised to provide new containment sump inspection requirements associated with the new strainers.

3. Replaced the LOCTIC containment analysis methodology for analyzing the response to postulated pipe ruptures inside containment, including a loss of cooling accident (LOCA) and a main steam line break, with the NRC-approved GOTHIC evaluation methodology discussed in Dominion Topical Report DOM-NAF-3-0.0-P-A. The change to the GOTHIC code provides margin in LOCA peak containment pressure and other accident analysis results.

4. Revised the Surry Units 1 and 2 LOCA Alternate Source Term (AST) analysis to include the effects from changing the RS pump start methodology and from the other modifications associated with the GSI-191 project. The change to the RS pump start methodology results in a short-term increase in air leakage from the containment and a short-term reduction in spray removal of radioactive isotopes from the containment atmosphere.

5. Revised and/or created procedures and programs to ensure that future changes to the plant are evaluated for their effect on the ability of the new containment strainers to perform their design function.

6. Trained operators on the operation of the RS and LHSI systems with respect to the new containment strainers.

Conservatisms

To ensure that the analyses and the modifications that were implemented appropriately and effectively addressed any uncertainties with considerable margin, the following conservatisms were included to address the sump performance issues discussed in GL 2004-02:

1. Testing and analyses for strainer head loss and vortexing were performed with the following conservatisms:

   - A reduced-scale test tank (Rig 33) was used to determine debris strainer design size and fin pitch by measuring debris head loss. The small diameter of the tank and the constant stirring ensured that a minimal amount of the debris settled on the floor of the tank thus maximizing the amount of debris and subsequent head loss across the test fins. Settling of small debris in containment is expected to be significant especially in areas remote from the strainer.

   - The maximum head loss is dependent on formation of a thin-bed on the strainer surface. Formation of a thin-bed is dependent on a small quantity of fiber mixing with all of the particulate on the strainer. Additional fiber, beyond the minimum quantity required for the thin-bed tends to produce lower head losses. Thin-bed formation conservatively used the minimum quantity of fiber necessary to form a thin-bed in combination with the maximum large break (LB) LOCA particulate load. This conservative combination is very unlikely to occur at the strainer for either a small break LOCA or a LBLOCA.

   - Vortexing analysis and testing showed no vortexing with a strainer that has zero submergence (water level at the top of the strainer). The submergence at the beginning of recirculation is at least three inches for the RS strainer and eight inches for the LHSI strainers. Submergence increases as RWST water continues to be sprayed into containment.

   - Maximum head loss is calculated at the minimum containment sump water level. The minimum water level only occurs at the beginning of recirculation and water level increases as additional RWST water is sprayed into containment. The maximum head loss will not be established until significantly after RS pump start and, based on head loss testing, will not occur until significantly after the approximately 2 hours required for all of the RWST water to be pumped into containment.

   - Head loss testing involved adding all of the particulate to the test tank prior to the addition of any fiber, and then adding fiber in increments to gradually build a thin-bed on the strainer. An actual break is much more likely to mix all of the available fiber and particulate together in the sump pool so that they arrive at the screen together and thus are unlikely to form a thin bed since there is likely to be more fiber in the mix than is necessary for thin bed formation. This will lead to lower head losses.

2. Test evaluations demonstrate that a fully formed thin-bed of debris requires significant time (hours) to form and that formation of a thin-bed is dependent upon disturbing settled debris throughout the test tank. Consequently, a worst-case thin-bed of debris would be difficult to form and would not be expected to form until several hours after sump recirculation is initiated. Significant debris settling and sump water subcooling occurs during the formation of a debris-bed so additional NPSH margin is available for chemical effects head loss. However, as a conservative measure, chemical effects testing began with an established debris thin-bed on the strainer fin and was conducted for the 30-day mission time.

3. The debris load in head loss testing was taken from the debris transport calculation, which conservatively credits no particulate settling.

4. Debris introduction procedures in chemical effects testing ensured minimum near-field settling and resulted in conservatively high debris bed head losses.

5. Debris introduction was accomplished in a carefully controlled manner to result in the highest possible head loss. Particulate was introduced initially, which was followed by discrete fiber additions after the particulate debris had fully circulated.

6. Only small fines of fibrous debris were used in head loss testing as if all the fibrous debris erosion, which is expected to take a considerable amount of time, occurred at recirculation start.

7. Debris bed formation during testing included agitating (or "stirring") the settled debris to ensure maximum debris on the strainer. However, any turbulence in post-LOCA containment sump water is expected to be localized to limited areas of the strainers. Consequently, much of the sump water will be quiescent, which would promote debris settling.

8. Particulate settling in head loss testing was conservatively minimized through use of a lower density walnut shell particulate as a surrogate for the higher density epoxy coating particulate that may be present in post-LOCA sump water.

9. Downstream wear analysis used the LBLOCA particulate load to determine abrasive and erosive wear. This is a conservative particulate loading, in view of the following:

   - Much of the particulate included in analysis is unqualified coating that is outside the break zone of influence (ZOI). This unqualified coating is assumed to dislodge due to exposure to the containment environment. However, such dislodgement is likely only after many hours and days, if at all.

- The low velocity of the sump water column and the significant number of surfaces throughout containment promote significant settling of particulate in containment. Settled coating will not be drawn through the sump strainer since the bottom of the RS strainer is located approximately six inches, and the bottom of the LHSI strainer is located approximately 19 inches, above the containment floor.

- The analysis assumes 100% strainer bypass of particulate, thus conservatively maximizing the effects of downstream wear.

10. Chemical effects testing results were conservative based upon several conditions:

- Aluminum corrosion amounts were calculated at high pH (pH 9), where aluminum corrosion and release rates are high. Testing was performed at neutral pH (pH 7), where aluminum solubility is low to encourage aluminum compound precipitation. Sump water pH is expected to be approximately 8 in the long-term.

- The minimum sump water volume at specified times post-LOCA were used to maximize the calculated sump aluminum concentrations.

- The analysis of aluminum load conservatively does not account for the possible inhibitory effect of silicate or other species on aluminum corrosion.

- The rate of corrosion is maximized by analysis that does not assume development of passive films, i.e., no aluminum oxides remain adhered to aluminum surfaces. The formation of passive films could be credited to decrease the corrosion and release rates at long exposure times. Consequently, it is conservative to assume that all aluminum released by corrosion enters the solution.

- All aluminum released into the solution is conservatively assumed to transport to the debris-bed instead of plating out on the multiple surfaces throughout containment. During bench-top testing, aluminum plated out on glass beakers and, during reduced-scale testing, aluminum plated out on fiber. It is reasonable to expect that a portion of the aluminum ions released into solution will plate out on some of the multiple surfaces in containment prior to arriving at the debris-bed on the strainer.

- Chemical effects test evaluations conservatively neglect the effect of the presence of oxygen in the sump water. The corrosion rate of aluminum in aerated pH 10 alkaline water can be a factor of two lower than that measured in nitrogen-deaerated water. This data is in NUREG/CR-6873, "Corrosion Rate Measurements and Chemical Speciation of Corrosion Products Using

Thermodynamic Modeling of Debris Components to Support GSI [Generic Safety Issue]-191."

11. Aluminum release analysis was conducted using the release rate equation developed by AECL,

$$\text{Release Rate (mg/m}^2\cdot\text{s)} = 55.2\cdot\exp\left(1.3947\cdot pH - \frac{6301.1}{T}\right) \qquad T \text{ in °K}$$

which can be more conservative under certain conditions than the release rate equation specified by Equation 6-2 of WCAP-16530-NP,

$$\text{Release Rate (mg/m}^2\cdot\text{min)} = 10^{14.6904-4.64537\cdot\left(\frac{1000}{T}\right)+0.04455\cdot pH^2-1.20131\cdot pH\cdot\frac{T}{1000}} \qquad T \text{ in °K}$$

Using this latter equation, a 30-day aluminum release of 10,900 g is obtained, which is 20% less than the 13,600 g predicted by the AECL model. Both quantities of accumulated aluminum are less than the acceptable sump aluminum load of 14,200 g, which was calculated from the maximum tested strainer aluminum loads in Rig 89 testing and assumed the worst-case flow scenarios for accumulation of aluminum on either the RS or LHSI strainer.

12. NPSH margins were determined with the following conservatisms:

- The calculation of NPSH available used the NRC-approved methodology in topical report DOM-NAF-3, Rev. 0.0-P-A, "GOTHIC Methodology for Analyzing the Response to Postulated Pipe Ruptures Inside Containment," September 2006. The methodology includes assumptions that minimize the contribution of containment accident pressure to the calculated NPSH margin and that maximize the sump water temperature (and thus the vapor pressure of the pumped fluid).

- The NPSH analysis includes conservatisms that ensure a minimum containment water level is used. Conservative assumptions are made for water holdup in spray system piping, water trapped from transport to the containment sump in volumes (e.g., the refueling canal and reactor cavity), condensation films on heat structures, films on platforms and equipment that form after spray is initiated, other losses, and spray water droplets in the atmosphere. Conservatisms are also applied to the available water sources: no contribution from the chemical addition tank; initial RWST volume of 384,000 gallons (versus Technical Specification minimum of 387,100 gallons); the containment sump is empty at the start of the LOCA (normal operation maintains approximately 500 gallons in the pit); and, +2.5% RWST wide range level uncertainty (9738 gallons) is applied in determining the initiation of RS and

LHSI recirculation (the minimum NPSHa for the LHSI pump occurs right after recirculation mode transfer to the sump).

- In accordance with topical report DOM-NAF-3, Rev. 0.0-P-A, explicit analyses were performed to identify the limiting set of conditions (break location, plant operating conditions, equipment performance, single failure) that produces the minimum NPSH available for each pump (LHSI, IRS, and ORS). This deterministic approach ensures that all variables are biased in their most adverse direction. For scenarios other than the most limiting case identified for each pump, additional NPSH margin exists.

- For evaluation of short-term pump NPSH margins, the maximum debris bed head loss from the test program was compared to the minimum NPSH available that occurs during a transient time when a debris bed is only just beginning to form on the strainer fins. Testing performed by AECL has shown that several hours to days are required to reach the maximum debris bed head loss that was used in the short-term NPSH margin evaluation.

- There is conservatism in the methodology used for scaling strainer debris bed head loss from test temperatures to higher specified sump temperatures. The debris bed will expand slightly when head loss is lower, i.e., at the higher sump temperature, the bed would be expected to be slightly more porous than at the lower test temperature. The assumption of a purely linear relationship between head loss and viscosity for scaling to higher temperatures is conservative.

Remaining Actions

The remaining commitments to be completed will further demonstrate the sufficiency of the corrective actions taken to address the containment sump performance issue and to provide additional margin. These actions are as follows:

1. Resolution of downstream effects for the fuel and reactor vessel,
2. Re-installation of air ejectors on the Units 1 and 2 LHSI pump cans, and
3. Completion of a Finite Element Analysis (FEA) demonstrating the acceptability of the 18" band spacing on the Surry insulation jacketing.

These items are discussed in Attachment 1.

Conclusion

Even with the three remaining activities noted above, based on the testing and analyses, modifications, and conservatisms described above, as well as the detailed information provided in Dominion's previous supplemental responses dated February 29, 2008, and February 27, 2009, there is reasonable assurance that the Surry Units 1 and 2 ECCS can provide long-term cooling of the reactor core following a

DBA. The ECCS system can remove decay heat so that the core temperature is maintained at an acceptably low value for the extended period of time required by the long-lived radioactivity remaining in the core. In addition, the CSS can operate to reduce the source term to meet the limits of 10 CFR 50.67 and remove heat from containment for at least 30 days following a DBA.

It is therefore concluded that Surry is in compliance with the applicable regulations as discussed in GL 2004-02, and the containment sump issues discussed in GSI-191 and GL 2004-02 have been adequately and thoroughly addressed for Surry Units 1 and 2.

ATTACHMENT 3

List of Regulatory Commitments

**VIRGINIA ELECTRIC AND POWER COMPANY
(DOMINION)
SURRY POWER STATION UNITS 1 AND 2**

List of Regulatory Commitments

Surry Power Station Units 1 and 2

The following table identifies those remaining actions committed to by Dominion for Surry Power Station Units 1 and 2 to resolve the containment sump performance issues identified in GL 2004-02.

No.	Commitment	Due Date/Event
1	Dominion commits to perform Finite Element Analysis (FEA) modeling to demonstrate/verify the acceptability of the stainless steel insulation jacketing with 18" band spacing used in the Surry Units 1 and 2 containments.	January 31, 2010
2	Dominion commits to re-install air ejectors in the Surry Units 1 and 2 Low Head Safety Injection (LHSI) pump cans to ensure the water level inside the can will remain well above the suction pipe nozzle, thus preserving calculated NPSH margin.	During the fall 2010 Refueling Outage for Surry Unit 1 and the spring 2011 Refueling Outage for Surry Unit 2
3	Dominion commits to: 1) demonstrate that in-vessel downstream effects issues associated with the reactor vessel/components and fuel are resolved by showing that the Surry plant conditions are bounded by the final WCAP-16793-NP and the corresponding final NRC staff Safety Evaluation (SE), 2) address any conditions and limitations that may be included in the final SE, and 3) inform the NRC of the results of this effort.	Within 90 days of issuance of the final NRC staff SE on WCAP-16793-NP